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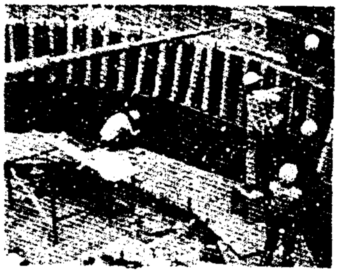

REPAIR, EVALUATION, MAINTENANCE, AND
REHABILITATION RESEARCH PROGRAM

TECHNICAL REPORT REMR-EM-4

HYDROELECTRIC GENERATOR AND GENERATOR–MOTOR INSULATION TESTS

by

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HY	Hydraulics	OM	Operations Management
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COVER PHOTOS:
TOP – Aerial view of Richard B. Russell dam and powerhouse, Savannah River, GA.

BOTTOM – Split coils being installed at McNary Unit 14, Columbia River, OR.

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19 ABSTRACT (Continue on reverse if necessary and identify by block number)

This report is a general treatise on insulation testing for Corps of Engineers hydroelectric generators and generator motors. Included are descriptions of the basis for generator ratings, the effect of operating and service conditions, types of insulation systems, and a complete description of visual inspections and electrical tests. Tests covered are the routine and special tests accepted by the industry for insulation systems for the generator stator, rotor, and stator core.

A discussion and recommended criteria for rewinding generators are included in this report along with detailed guidance on criteria for generator uprating.

The field offices with responsibility for hydropower were surveyed about current routine generator insulation testing. Present practices by the Districts and (Cont'd)

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Divisions are summarized. A recommended routine inspection and test program is included.

Also included is a summary of the Corps of Engineers experience with thermosetting insulation. Experience from the early 1950's with Westinghouse polyester insulation to the present with epoxy impregnated insulations is included.

PREFACE

The study reported herein was authorized by Headquarters, US Army Corps of Engineers (HQUSACE), as part of the Electrical and Mechanical problem area of the Repair, Evaluation, Maintenance, and Rehabilitation (REMR) Research Program. The work was performed under Civil Works Research Work Unit 32330, "Nondestructive Evaluation of Electrical Insulation in Rotating Machinery," for which Mr. Ray McCormack is Principal Investigator. Mr. Bob Pletka is the REMR Technical Monitor for this work.

Mr. Jesse A. Pfeiffer, Jr. is the REMR Coordinator at the Directorate of Research and Development, HQUSACE; Mr. Jim Crews and Dr. Tony C. Liu serve as the REMR Overview Committee; Mr. William F. McCleese, US Army Engineer Waterways Experiment Station, is the REMR Program Manager; Dr. Ashok Kumar is the Problem Area Leader for the Electrical-Mechanical problem area.

This work was conducted by the US Army Construction Engineering Research Laboratory (USACERL) under the general supervision of Dr. R. Quattrone, Chief of Engineering and Materials Division (EM). The editorial reviewer was Linda Wheatley, USACERL Information Management Office.

COL Carl O. Magnell was Commander and Director of USACERL, and Dr. L. R. Shaffer was Technical Director.

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PART I: INTRODUCTION

Background

1. Currently there is no guidance Corps-wide for inspection, testing, and maintenance for electrical insulation for hydroelectric generators and generator-motors. Because of the increasing age of the insulation on older machines and widespread difficulty with new insulation systems, increasing emphasis is being placed on electrical insulation inspections and tests. At present there is a great deal of difference in routine and special tests performed by the divisions with responsibility for hydropower; for example, there are no uniform criteria to help determine when units should be rewound. Considerable work is needed in the Corps and throughout the industry to standardize procedures for inspection and testing of generator and generator-motor insulation.

Objectives

2. The first objective of this report is to describe generator-insulation systems used on Corps of Engineers' generators, the effects of operation and service conditions on the insulation, and the visual inspections and electrical tests on generator insulation accepted by the industry, the purpose of the tests, how the tests are made, and how the results are interpreted. The second objective is to develop guidance to help Corps of Engineers' divisions determine when a generator should be rewound and how to uprate generators when they are rewound. The third objective is to survey the Corps on the current practice for insulation inspection and testing and rewind criteria and to develop a recommended program for periodic routine inspection and testing. The final objective is to provide a brief summary of Corps of Engineers' experience with thermosetting stator insulation systems.

Approach

3. A great deal of information has been published on inspection and testing of high-voltage insulation applicable to large alternating-current generators and motors. A comprehensive literature search was made to identify state-of-the-art insulation evaluation technology; a survey was made of insulation maintenance practices throughout the Corps, and the information gathered was used as a basis for this report.

Scope

4. This report applies to all Corps of Engineers' hydraulic, turbine-driven, alternating-current generators and generator motors rated more than 10,000 kVA, 6,600 V.

PART II: INSPECTION AND TESTS

5. Over the years, manufacturers and users of large hydroelectric generators have searched for tests that will give a reliable indication of the remaining service life of high-voltage insulation. At present, however, there is no known way to predict how much longer a generator will be able to provide a reliable source of electrical energy. The number of years of service before units must be rewound varies widely, depending on, among other things, the insulation materials and how they are applied, the installation of the coils, routine maintenance, and operating and service conditions. An adequate routine maintenance, inspection, and testing program can, however, provide assurance that the insulation is in good condition, can result in detection of minor problems before they become major, and can indicate long-term trends as well as evaluation of current conditions. A comparison of the data obtained from a regular inspection and testing program will give some indication of the need for future repairs or replacement. The maintenance program should include both partial and major disassemblies, visual inspections, and applicable electrical tests of proven significance. Descriptions of these inspections and tests are included in the following pages and are covered in more detail in the references.

Basis for Ratings

6. Although current standards for the generator ratings specify maximum stator-temperature rises of 70° and 75° C for thermoplastic and thermosetting Class B insulation and 80° C temperature rises for Class B field-winding insulation (American National Standards 1977, 1982), until recently, no Corps of Engineers' generators were rated on this basis. Until 1985 all Corps of Engineers' generators were rated for a maximum stator- and field-temperature rise of 60° C when operated at rated kVA, powerfactor, and voltage. The generators were also designed for continuous operation at 115 percent of nameplate rating with stator- and field-temperature rises exceeding 60° C. The temperature rises are all based on a maximum cooling-air temperature of 40° C. If the cooling-water temperature is so high that the cooling-air

temperature exceeds 40° C, loading is reduced so that the total temperatures are not exceeded.

Effects of Operating Conditions

7. Insulation is capable of operating up the applicable temperature limits with normal life expectancy, but there may be determinatal effects on other parts of the machine. Also, useful life is extended by operation at lower temperatures. For normal life expectancy, the hot-spot temperature should not exceed the limiting temperature. Hot-spot temperatures cannot be measured, so realistic additions must be made to the maximum observable temperatures in order to estimate the hot-spot temperatures and maximum loading. Changes of load and temperature and the rate of change subject the insulation to additional mechanical stresses. Regulating units that have widely variable loading generally have reduced insulation life compared to base-loading units. Differential expansion between the stator core and winding can result in damage to the insulation. Since the copper conductor temperature changes more rapidly than the core temperature, slow changes in load reduce differential expansion.

8. Stator temperatures are measured with resistance-temperature detectors (RTDs) embedded in the stator winding between the top and bottom stator coils. The difference between the observable and the conductor temperature depends on the thickness of the coil insulation, slot proportions, temperature gradients, and other factors so that, even though the observable temperature is low, there is not necessarily a margin for overloading. Field temperatures are measured by measuring field resistance. This measurement gives an average field-winding temperature that is somewhat less than peak temperature so that an adequate margin must be allowed for the difference between average and hot-spot temperatures. The generator stator capacity limits the kVA output from operation at minimum power factor underexcited to rated powerfactor. The field capacity limits the generator output for powerfactors rated less than overexcited. When generators are operated above rated voltage, higher excitation currents are required with corresponding higher field and stator core temperatures. When generators are operated at less than rated voltage, higher armature currents are required with

corresponding higher stator winding temperatures. A family of generator capability curves showing kW and kVAr (kilovolt-amperes reactive) capacity for a range of voltages should be used for determining unit capability over a range of voltages and powerfactors. Further information is provided by the Institute of Electric and Electronic Engineers (1977a).

Effects of Service Conditions

9. Insulation systems are adversely affected by thermal, mechanical, and electrical stresses and contamination that can cause insulation deterioration, reduced life, and failure.

Thermal aging

10. The life of insulation varies inversely with the operating temperature. A long-used rule of thumb is that insulation life at temperatures near the upper temperature rating is decreased one-half for each 10° C rise in temperature (Foley 1981). Loss of insulation properties is caused by a combination of changes in mechanical and electrical properties, mostly as a result of chemical reactions.

Mechanical stress

11. Thermal expansion and contraction of insulated copper conductors induces mechanical stress in the insulation which, in time, can cause loss of integrity. Mechanical vibration caused by magnetic forces on the conductors can cause abrasion of the insulation. Mechanical damage can also be caused by abnormal forces resulting from short-circuits and out-of-phase synchronizing, and from the effects of foreign objects such as magnetic particles.

Overvoltages

12. High-impulse voltages caused by lightning and switching surges can cause insulation damage and electrical breakdown. This damage occurs when the intrinsic electrical strength of the insulation is exceeded, causing electrons in the insulation to gain sufficient energy to puncture the insulation.

Contamination

13. Contamination can cause damage to insulation by providing a path for surface leakage currents, by causing chemical reactions that adversely affect the electrical or mechanical strength, or by reducing heat dissipation and thereby causing higher than normal operating temperatures. Some contaminating

substances are moisture, oil and greases, dust and dirt, and industrial chemicals. Prevention of contamination between the rotor-grounded pole steel and insulation collars is important.

Partial discharges

14. Slot discharges between ungrounded coil sides and the stator core can cause erosion of the coil ground wall insulation. Corona in insulation voids and on end turns can damage insulation by erosion and chemical attack. Slot discharges occur when coil vibration results in loss of coil surface grounding, allowing a sufficiently high charge to develop to cause fairly high-energy electrical discharges between the insulating surface and the stator core. When potential gradients are sufficiently high to cause slot discharges or corona, ionization generates charged particles sufficiently energetic to break chemical bond in the insulation surfaces, causing erosion of the insulation and sometimes forming destructive chemicals.

15. Generator windings are wye-connected with the neutral grounded. Operating voltages decrease from the line-to-ground voltage at the generator terminals to zero volts of the generator neutral, and the coil-insulation-voltage stress-to-ground varies accordingly, depending on the location of the coil in the winding. Coils farther from the neutral are more susceptible to damage from partial discharges.

Insulation Systems

Stator

16. Stator coils consist of insulated strands made into single or multiturn coils. Multiturn coils are insulated between turns, and both types have an outer covering of ground-wall insulation. One coil side is in the inner or top of a stator core slot, and the other coil side is in the outer or bottom of a nearby slot, forming a two-layer winding. The coils are connected in series to make up one of the circuits per phase. The strands are transposed in the slot (Roebel Transposition) for single-turn coils and in the end turn connections or jumper connections for multiturn coils. Figure 1 shows a stator slot cross section and two single-turn coil sides of one typical winding design presently in use. Until the 1950's, most stator coil turn and ground insulation was made with mica reinforced with fibers, such as

glass, to form a suitable tape to wrap around the turns. After the turns were taped, the insulation was impregnated with an asphaltic compound to form a fairly soft thermoplastic type of insulation. An outer protective covering of glass or ferrous asbestos tape was applied to the coils. It was treated with a semiconducting compound on the slot portions, extended a suitable distance beyond the slots, and graded. The strands were insulated with asbestos, glass, mica tape, and varnish. This insulation system was used successfully for many years, but because of its fairly low dielectric strength and correspondingly large insulation thickness, poor heat dissipation, large stator-core diameter, and thermomechanical problems with longer coils, it became less practical and economical as units increased in size.

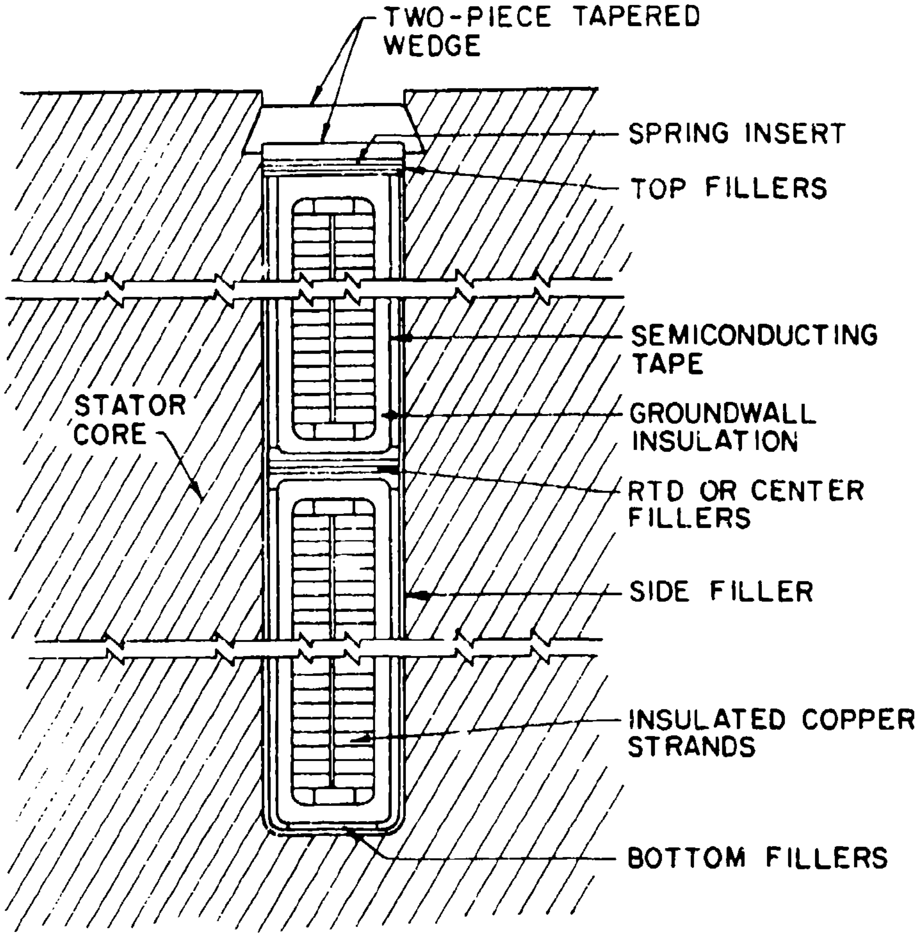


Figure 1. Typical current stator slot cross section.

17. Thermosetting insulations were developed to overcome these difficulties. Polyester or epoxy impregnating materials were used to replace the asphaltic compounds. These materials give a hard, inflexible, dense, homogenous insulation. These insulations have improved dielectric strength, reduced insulation thickness, and improved heat dissipation. This insulation is not subject to thermal degradation (Mitsui, et al. 1983) or internal ionization to the same degree as older asphaltic insulations, but because of a lack of flexibility, it is subject to a greater extent to the development of coil looseness in the slots, abrasion of the insulation from mechanical vibration, and development of slot discharges and insulation erosion. Because the insulation is inflexible and hard, it cannot deform to accommodate slot irregularities, but the insulation system will compress under thermal and electromechnical stresses requiring close control of coil dimensions and installation with sufficient prestress to keep the coils tight under extended operating conditions.

18. Resistance temperature detectors (RTDs) are embedded in the stator winding used to monitor stator temperatures. The resistance elements are located between the top and bottom coils and are encapsulated in an insulating material with insulated leads brought to the generator terminal cabinet. The RTD insulating material is assembled so that the unit is the same width as the slot, is in contact with both top and bottom coils, and is isolated from any contact with the cooling air.

Rotor

19. Field coils consist of a copper strap wound over an insulating spool around the field poles. The copper turns are insulated with tape or strip materials such as mica, fiber-glass or synthetic material with resin bonding. The turn insulation is cemented to the adjacent turns to form a mechanically rigid coil. The coils are insulated at the top and bottom with insulating collars and hardware that keep the coils from moving under maximum overspeed conditions. An alternative method consists of insulation integral with the turn insulation to bond the field coil to the pole body. Flexible connections are used between the field poles to connect the field coils in series to make up the complete field winding. Both turn and ground insulation are limited to Class B temperature rises. Generator fields at Corps of Engineers' projects are nominally rated from 125 to 500 V. Generator short-

circuits and excitation system ceiling voltages can, however, impress voltages on the field several times rated. Dielectric strength is not as important a design consideration as mechanical strength and heat-resisting properties. The electrical supply to the field is accomplished by cable or bus from the exciter or excitation equipment through brushes and sliprings mounted on the rotor, which are connected to the field winding. The connections to the brushes (brush rigging) are usually insulated with a molded compound or laminate made from glass or synthetic fibers, bonded and impregnated.

Stator core

20. The stator core is made up of thin sheet-steel laminations that are insulated on both sides with a thin coating of insulating varnish or other suitable material. Waterglass, which is used on old machines, was subject to deterioration if proper clamping pressure was not maintained. This interlaminar insulation is needed to reduce eddy-current losses. The rated temperature rise for the core is 55° C, but loss of insulation between laminations can cause excessive localized heating. Failure of interlaminar insulation usually results from a stator-winding failure or from core vibration and normally results in a gradual temperature rise. Core tightening through-bolts are used to hold the laminations tightly to reduce vibration and damage to the core insulation and to reduce fretting of the laminations. The through-bolts on some machines, depending on stator core design, are insulated from ground throughout their length and bonded with suitable insulation. In this case, the nuts and washers are also insulated from ground.

Mechanical and Visual Inspections

21. In addition to specialized electrical tests, visual inspections are necessary for a thorough evaluation of the insulation systems. Visual inspections can detect many developing problems that, unless corrected, could lead to reduced reliability and serviceability. All windings are subject to harmful conditions and, in time, can develop weaknesses that can lead to reduced life and failure. A regular schedule of visual inspections involving both partial and major disassembly should be adopted. Some of the inspections that can be made without removing the rotor include observation of the stator end turns and connections, circuit rings and connections, support insulation

(such as blocks), braces and insulators, lashing and ties, top and bottom wedges, coils, slot packing and core laminations, brush rigging insulation and, to some extent, the field poles and field winding.

Stator

22. Visual inspection should include observation of the end turns for evidence of corona attack from deposits that can be white, gray, or red or from erosion of the insulation, especially where adjacent turns are markedly different potentials. When corona is occurring, it can be seen in the dark on the end turns, circuit rings, and connection when the winding is energized at rated voltage. Thermal aging is evidenced in asphaltic- and polyester-type insulation by softness, sponginess, swelling, darkening, or puffiness of the insulation, migration of the insulating compound, separation or delamination of the insulating tapes, and separation of the insulation from the conductor.

23. Evidence of thermomechanical damage usually shows up as cracks in the insulation near the ends of the slots. Removal of the wedges at the ends of the slots should be given consideration when cracks are discovered where the conductors leave the slots, as cracks are also likely to be in the insulation in the slot ends.

24. Coils should be examined for contamination by materials such as carbon dust, oil. moisture, and abrasive materials such as magnetic particles. Stator coils should be checked to make sure they have not become loose in the slots. Loose coils will usually be accompanied by loose wedges, moving slot fillers and packing, and evidence of movement of coils where they enter the slots and where supports, braces, and ties are located. Loose wedges can be detected by the sound made when the insulation is tapped with a metal object such as a penknife. With a feeler gage, clearances between the slot and coil can be checked for compliance with the manufacturer's recommendations. Inspection for coil tightness is most important for windings with thermosetting insulation. Side, top, and bottom filler should be inspected to make sure it has not slipped down or migrated upward. This movement is fairly common with loose coils and can result in damage to the lower end-turn insulation. Detailed information on visual inspections for windings with thermosetting insulations are described by the Institute of Electric and Electronic Engineers (1981) and the guide prepared by Ontario Hydro for generator rewinds. Corona damage to the end turns, thermal aging,

and the thermomechanical damage are more likely to occur on thermoplastic insulated windings. Coil insulation should be inspected for damage from electromagnetic stresses such as cracking and abrasion and end-turn distortion. Core clamping plates and the stator core iron should be inspected for looseness and fretting of the laminations. Evidence of red dust is an indication of fretting. Laminations should also be inspected to overheating as evidenced by discoloration. The stator frame should be closely inspected for cracked welds.

Field windings

25. Field coils should be inspected for any movement or distress resulting from centrifugal forces from normal operating speeds or overspeed. Coil movement can be detected by distortions of the turns, loose insulating collars or washers, powdered insulation in the air ducts, and the appearance of red oxide at metallic joints. The field poles, coils, and connections should be inspected for overheating, looseness, and mechanical distress. The insulation supporting the brush rigging should be inspected for flashovers or leakage currents. The ammortisseur winding and connections should be visually inspected under bright light for looseness, arcing, and for hairline circumferential cracks where the dowels are brazed to the shorting bars.

Frequency of inspection and tests

26. Inspection of the machine should be made in accordance with the contract requirements and the manufacturer's instructions. If no problems are discovered, partial disassembly during the annual maintenance along with the routine electrical tests described in the following sections will usually be satisfactory for a long time. If the warranties in the contract are extended beyond one year, there should be a complete inspection prior to the expiration of the warranties. The frequency and extent of special inspections and tests depend primarily on the results of previous inspections and tests. However, the history of experience with similar machines, severity of duty, manufacturer's recommendation, frequency of major overhauls, available manpower, and considerations of machine availability based on load demand and available head and flow also must be considered. Recommended routine inspections and tests are described in paragraph 69.

Routine maintenance

27. Whenever the machine windings get sufficiently dirty so that the polarization index is below two, they should be cleaned with a vacuum cleaner or dry low-pressure compressed air. If a winding is contaminated with hard to remove oil or chemicals, cleaning solvents that meet manufacturer's recommendations can be used. The solvent should be applied with a cloth and removed quickly. Abrasive blasting with crushed corn cobs or ground nut shells and compressed air is another way to clean windings that are badly contaminated with oil. This is an effective cleaning method, but unless done with care, it can cause abrasion of the insulation and, in tight places, can be difficult to remove; the crushed material may possibly block cooling-air passages. Except for cleaning, most hydrogenerator insulation should not require any other routine maintenance except possible touchups of end turns damaged by corona.

Repairs

28. Repairs to the insulation should be made in accordance with the manufacturer's recommendations and with materials and methods compatible with the existing windings. Two-piece tapered wedges with spring-type top packing fillers, two-piece wedges without springs, and one-piece wedges with springs are all available; these and other designs should be examined for replacement of the older types for repair of loose coils. Detailed repair procedures for thermosetting insulations are described by IEEE (1981). Loose ties, braces, and insulating blocks can be retied and secured with epoxies or insulating varnish, glass cord, and fabric-reinforced phenolics. Epoxy can be used to secure loose laminations. Semiconducting silicone rubber CRTV (Conductive Room Temperature Vulcanizing) can be applied to coil surfaces to re-establish coil surface grounding. Ground-wall insulation can sometimes be temporarily repaired with suitable insulating compounds. Some older units have been revarnished primarily to reduce absorption of moisture and collection of dust on the windings. Revarnishing the windings has the disadvantage of possibly trapping contaminants and moisture in insulation cracks and can affect the thermal conduction of the insulation. Individual coils or half-coils can be replaced with spares or cut out of the winding and bypassed. It has been common practice to operate units for extended periods with coils cut out of the winding.

Protection during downtime

29. During inspection and testing, the machine should be kept clean and dry with the temperature of the parts maintained at a few degrees above the dewpoint of the surrounding air. All electrical parts with insulated windings or laminations that are removed should be stored in a clean, dry place and protected against extreme temperatures and temperature variations. Insulation should be protected against termites and rodents. All parts should be regularly inspected. When the rotor is removed, the rotor spider should be supported so that the weight is distributed uniformly to prevent permanent distortion. Further information is supplied by the National Electrical Manufacturers Association (1972).

Electrical Insulation Tests

30. Electrical tests can be useful in detecting existing weaknesses in insulation and can give an indication of expected service reliability. The following tests can indicate weaknesses in the insulation:

- a. Insulation resistance and dielectric absorption.
- b. Overvoltage proof tests.
- c. Partial discharge tests.
- d. Turn-to-turn tests.
- e. Rotor winding impedance tests.

31. These tests can be used to give an indication of expected service reliability:

- a. Insulation powerfactor tests.
- b. Controlled overvoltage tests.

32. When electrical maintenance tests are routinely made under as nearly identical conditions as possible, comparison of results can give valuable information on changes and deterioration. There are so many variables that it is usually not possible to define absolute values that are acceptable or unacceptable. The following tests can be included in a maintenance testing program:

- a. Insulation resistance and dielectric absorption tests indicate the degree of contamination of the insulating surface.

b. Insulation powerfactor and powerfactor tip-up tests give an average powerfactor for the winding; any localized high-power factor condition will not show up in this test. When these values increase between tests, a gradual deterioration of the insulation or increased insulation contamination can be assumed.

c. DC controlled overvoltage tests can be useful in evaluating the condition of the insulation when results are compared with previous tests made under the same conditions. These tests should only be made when repair facilities are available and at not more than the equivalent (1.7 times) of 125 percent of rated line-to-line voltage.

d. Generated frequency electromagnetic interference (EMI) tests that show an increase in EMI with about the same ambient noise as in previous tests, indicate an increase in partial discharges.

e. Winding resistance tests can indicate shorted turns or loose connections when adjustments are made for temperature differences in comparison with previous tests.

f. Ozone concentration tests that show a change in ozone concentration indicate a change in partial discharges.

Stator winding

33. Insulation resistance and dielectric absorption. Insulation resistance can be a useful guide in determining the condition of the insulation by the comparison of present and previous values. It is an essential test for determining the suitability of a machine for overpotential tests or for being placed in operation. It is not possible, however, to detect individual weak coils or to relate dielectric strength to insulation resistance. Insulation resistance is affected by moisture, surface contamination, the grading paint on end turns, the winding surface area, type and thickness of insulating materials, and the condition of the insulation.

34. General criteria have been developed as a guide for minimum values of insulation resistance. For generators rated 13.8 kV, the minimum resistance before making overpotential tests or placing the unit in operation is 14.8 megohms at 40° C for the entire winding, or twice that value for one phase with the other two phases grounded. This criterion is based on a minimum resistance in megohms at 40° C for the entire winding, or twice that value for one phase with the other two phases grounded. This criterion is based on a minimum resistance in megohms at 40° C equal to rated line-to-line

voltage in kV plus 1 (IEEE 1974). With good, clean, dry insulation, the insulation resistance will usually be much higher even for large machines. When a DC potential is applied to an insulating material, there will be three or four components of current that will flow. They are the capacitive current, absorption current, leakage or conduction current, and, if the potential is high enough, partial discharge current. Figure 2 shows how the first three current components vary with time when a steady DC voltage is applied to the insulation. Assuming constant voltage input, the capacitive current rapidly decays to zero and does not affect the resistance measurement. Absorption current decreases to zero over a much longer time and has an appreciable effect on the measurements. (Partial discharge currents are discussed under the section on partial discharges.) True resistance can be measured by a steady application of DC voltage until the absorption current decays to zero; however, this action can take quite a while. The absorption and leakage currents can be separated out since the absorption current is a power function of time and the leakage current is fairly constant with time. Details are described by E. B. Curdts (1984). Absorption current depends on the condition of the impregnating material. Increases in absorption current over a period of time indicate degradation of the bonding material, when the current is corrected to a reference temperature and everything else remains constant. Absorption current, however, decreases with increasing voids in the insulation so that the total effect depends on the balance. Absorption current can be determined from a plot of total current as shown in Figure 2. Absorption current can also be measured directly. When the winding is short-circuited, the discharge current is the same as the absorption current that flows when voltage is applied. Insulation resistance measurements are usually made at 1 min and at 10 min, and the measurements compared with previous test results. The values should be corrected to 40° C (IEEE 1974). Because of the decrease in current with time, the insulation resistance measured at 10 min will usually be higher than at 1 min with a continually applied, steady DC potential. If the insulation is clean and dry and in good condition, the insulation resistance will increase for 10 or 15 min or longer, but for insulation in poor condition, a steady value will usually be reached in only 1 or 2 min. When a history of insulation resistance is not available, the ratio of the resistance measured at 10 min to that at 1 min is an indication of

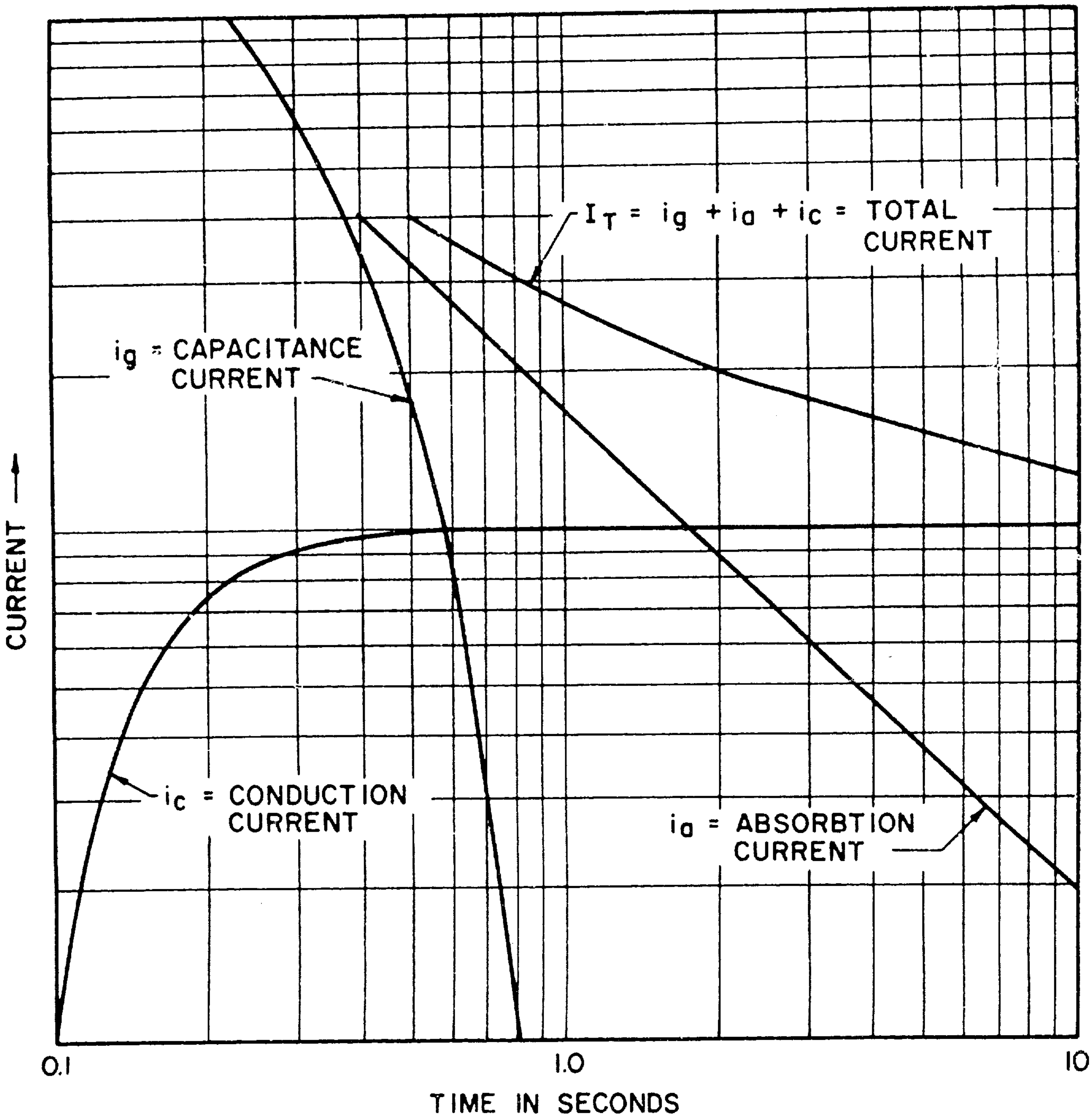


Figure 2. Components of current for insulation resistance test

suitability for service. This ratio is called the polarization index and has to be at least 2 before a machine is suitable for overpotential tests or for operation. Figure 3 shows how insulation resistance and the polarization index are affected by the condition of the insulation.

35. Testing should be done with equipment that will supply a regulated DC potential between 500 and 5,000 V; 2,500 V is commonly used. Tests on a single circuit or phase with the other circuits or phases grounded will permit comparing measurements, will include the insulation between circuits or phases, and will improve test sensitivity. In many cases, because of the difficulty of separating the windings, all three phases are tested at once.

36. Winding insulation resistance as a tool to evaluate the condition of the insulation is most useful when current and previous measurements are compared. To assure meaningful comparisons, the test conditions and equipment should be as similar as possible. The winding-under tests should be completely discharged before starting the test procedure, as a residual charge will affect the measurements and, for safety, must be completely discharged on completion of tests. Usually insulation resistance tests are made with a megger. A megger consists of a direct-current generator that supplies a constant voltage and a meter calibrated in ohms. The meter pointer has no restraining torque and assumes a position controlled by a current coil connected in series with the insulation-under test and a voltage coil connected across the generator output. Figure 4 shows a schematic diagram of the megger. Instruments with separate power supplies are also available to read ohms directly, or a voltmeter and microammeter can be used and resistance can be calculated. A microprocessor-controlled test instrument that measures "true resistance" is described by Reynolds and Leszrzynski (1985). The winding-under tests should be isolated from all external equipment, and leakage current and corona from the tests' leads should be avoided. The voltage should be raised to the test potential as quickly as possible when the test is started.

37. <u>AC high-potential tests</u>. AC high-potential tests are used as acceptance tests at the factory and in the field. They are also used to some extent as maintenance tests on machines in service. The tests demonstrate whether the electrical strength of the insulation is above a predetermined

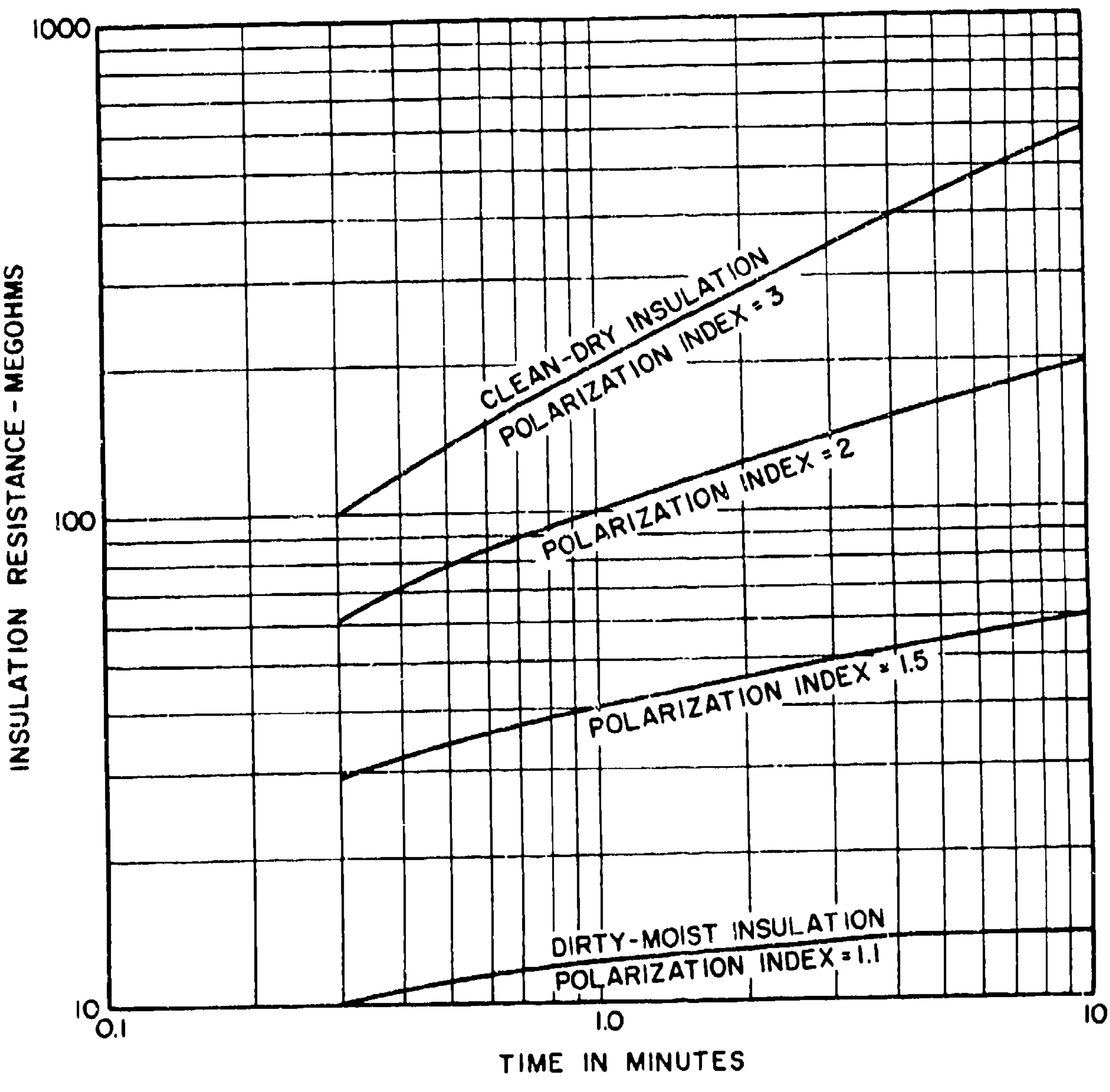


Figure 3. Insulation resistance with time for different insulation conditions

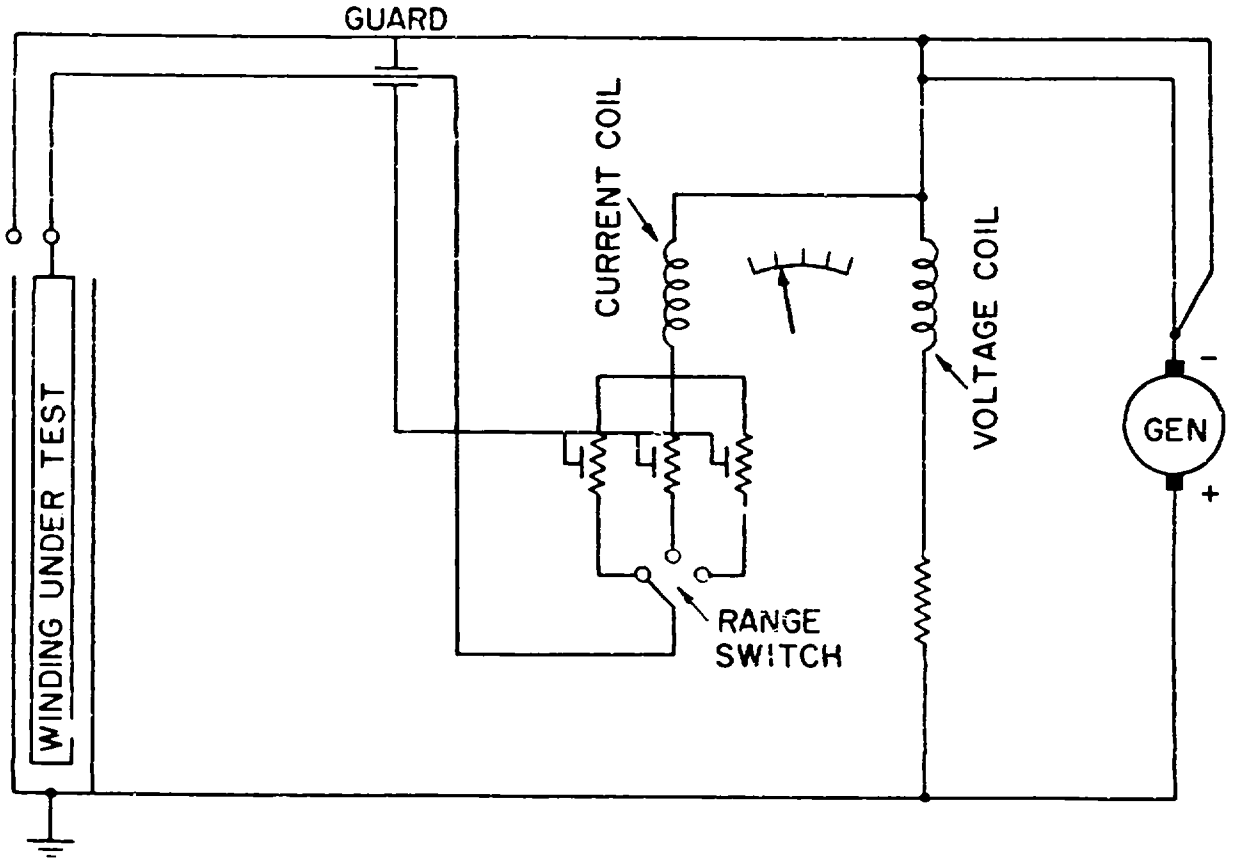


Figure 4. Megger electrical schematic

value. In AC high-potential tests, the magnitude of current flow has little significance. The test equipment for large machines, of sufficient capacity to supply the necessary charging current at test voltage, is beyond the capability of conventional portable test sets. Resonant test sets that reduce the kVA capacity required have been developed, but they still do not have the limited size, weight, and capacity of DC test equipment for maintenance testing. The tests are made on new coils or windings to demonstrate that they meet the 60 Hz-withstand-test voltage specified and to demonstrate suitability for sustained operation in service. These tests are performed primarily to detect flaws in the insulation that are caused by faulty manufacture, installation, or maintenance. The windings are tested at twice the normal line-to-line voltage plus 1,000 V for 1 min. This voltage is 28.6 kV root mean square (RMS) for 13.8 kV generators. After installation, a new winding is tested at 85 percent of this value. After a machine has been in service, test voltages are limited to 125 to 150 percent of rated line-to-line voltage. Only an overvoltage test will demonstrate adequate dielectric strength. It has been shown (Hunt and Vivion 1951, Johnson 1951) that tests at 125 to 150 percent rated voltage will not have an adverse effect on the life of sound insulation, but they are of sufficient magnitude to detect weaknesses or flaws that could lead to a failure in service. Maintenance overvoltage tests, when possible, should be made at the beginning of the unit overhaul so that repairs, if necessary, can be made during the scheduled outage.

38. Each phase should be tested separately, with the other phases grounded. The test potential should be increased smoothly and promptly to the desired value, held for one minute, and then decreased in the same manner. The leads of each winding should be connected, whether under testing or grounded, to avoid high voltage oscillations in the event of a failure. The humidity should be similar to that for normal operating conditions, and the winding should be dry and a few degrees above ambient temperature but should not exceed 40° C. For new winding acceptance tests, the temperature should be raised to the normal operating level. Both the winding resistance and the polarization index should be above the minimum values described in the section on insulation resistance and dielectric absorption. Although not essential, it is best to perform the tests with the rotor removed to facilitate inspection and repair of the windings in case of breakdown.

39. The test's voltage wave shape should be checked for distortion during the test, and the test equipment should limit the current to avoid damage in case of a breakdown. The AC supply voltage should be free from significant fluctuations in magnitude and frequency, and the test instruments should be calibrated with errors less than ± 3 percent of full scale. A hyprotronics series resonant test set can be used. DC and Very-Low Frequency Overvoltage Tests described in the following sections stress the insulation a little differently from normal operation but permit the use of small, easily portable test equipment.

40. <u>DC high potential tests</u>. For many years AC dielectric tests have been the standard method of proving the integrity of high-voltage generator insulation. Normal frequency dielectric tests, contrary to DC tests, subject insulation to the voltage gradients and stresses seen in service. To obtain a roughly equivalent DC test potential, a factor of 1.7 times the AC test potential has been accepted by the industry. This equivalent means that the insulation can probably withstand AC overvoltages in service that approximate the equivalent DC potential. In the past, there has been some concern that high voltage DC tests will shorten the life of the insulation by searching out minor defects and causing small leakage currents to flow that can increase and aggravate the flaw, especially since DC-controlled overvoltage maintenance tests can take 40 min or more to perform on one winding. DC dielectric tests have been in general use, however, for 20 years or more without any indication that DC high-potential tests have actually caused a reduction in insulation life. However, for machines that are subjected to routine controlled-overvoltage DC dielectric tests, it is good practice to limit the maximum overvoltage to the DC equivalent of 125 percent of rated line-to-line voltage or 29 kV for 13.8 kV generators. Some advantages of the DC overvoltage tests are the small, low-cost test equipment required, the possibility of comparing test results to detect insulation deterioration over a period of time, and sometimes to be able to predict a breakdown before it actually occurs. There have been instances, however, in which failures have occurred without warning, and there have been false indications that failure was imminent.

41. DC high-potential proof tests are made to demonstrate that the electrical strength of the insulation is above the specified value and is suitable for sustained operation. Controlled overvoltage tests are made by

raising the potential in a specified manner over a specified period of time. Both proof and controlled-overvoltage tests can be combined in the dielectric test procedure when the windings are new to obtain a benchmark for comparing results from subsequent tests. The normal procedure is to apply a low-voltage DC potential to the winding-under test, usually about 30 percent of the maximum voltage DC equivalent (about 9 kV for 13.8 kV generators) to determine the insulation resistance and polarization index before the high-potential tests are made. These should exceed the minimum values described in the section on insulation resistance and dielectric absorption to make sure the insulation is sufficiently clean and dry for overvoltage tests. The voltage is increased in equal 1-minute steps by an amount less than 3 percent of the final test voltage, usually about 500 V per step. Alternatively, the voltage can be increased at a constant rate. The test methods should be as nearly identical as possible between tests so that test results can be compared to detect changes in the condition of the insulation over a period of time. The voltage step adjustments should be made in the first 10 sec and should not be readjusted. Settings should allow for regulation of the test equipment. The current should be measured at the end of the periods, and current and voltage plotted as the test progresses. Any deviation from a smooth curve can indicate potential breakdown. An increase in current while the voltage is constant is also an indication of imminent failure. Figure 5 shows some indications of possible approaching breakdown.

42. Extrapolating the current-voltage curve may give some indication of what the breakdown voltage might be; however, sometimes breakdown can occur without any warning. A recorder recording current and voltage as a function of time is helpful, especial y when a constant voltage adjustment is used. Any deviation in the smoothness of the curve should be taken as an indication of imminent breakdown. The test should be discontinued at this point unless it is desired to "smoke out" insulation weaknesses for repair during the scheduled outage to avoid possible service interruptions. Continuation of the testing should only be done when continuity of service is vital, when the test voltage is not too much above the normal operating range, when repair facilities are available, and when there is reason to suspect the winding may fail in service. Assuming no deviations from a smooth curve are noted, the test can be continued to the maximum value. An alternate procedure for high

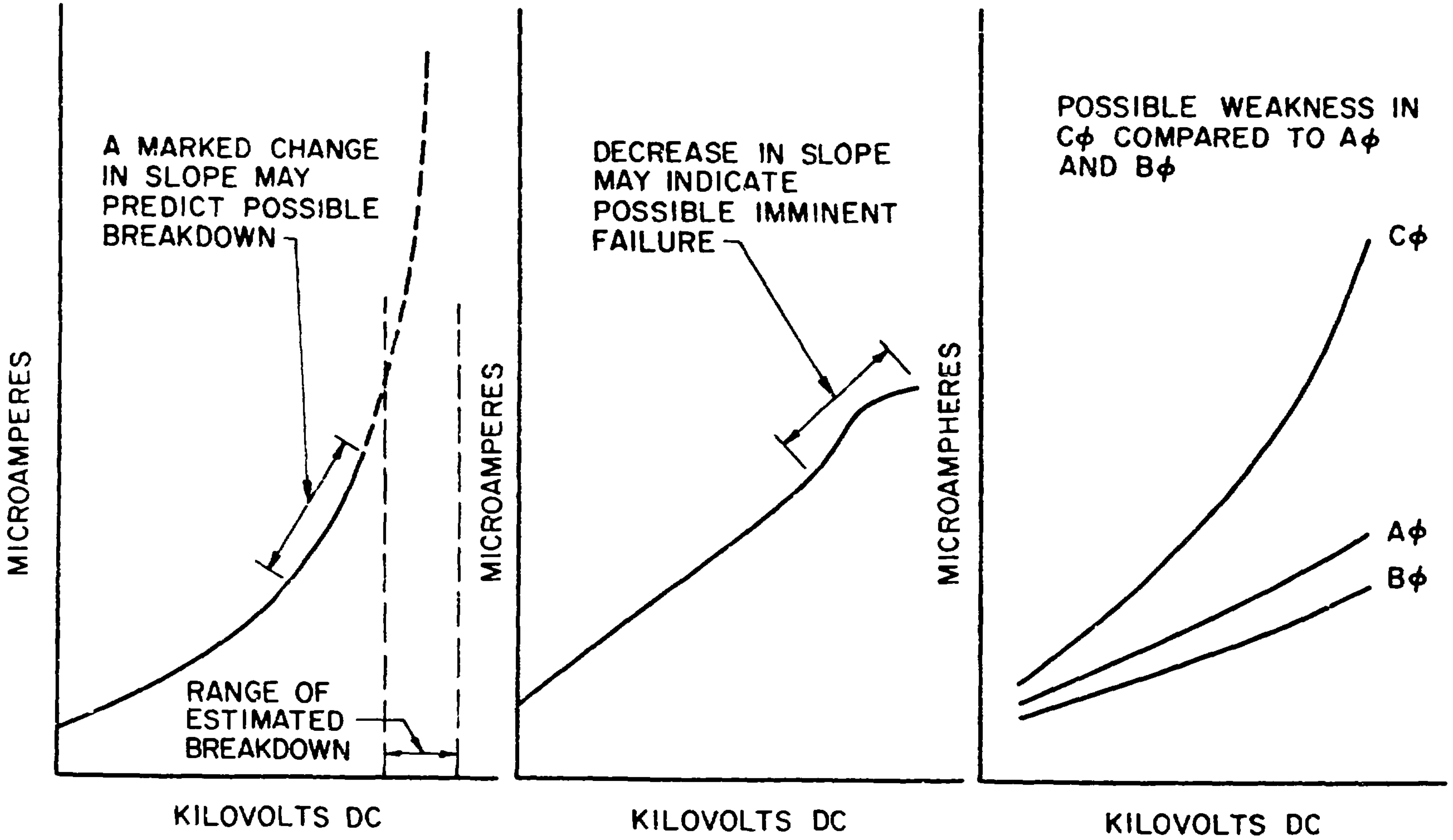


Figure 5. Interpretation of DC controlled overvoltage tests

voltage DC tests that allows determination of the leakage component of current is described in Appendix A of IEEE Standard 95 (IEEE 1977b). Tests should be made on the smallest section of the winding that can be easily isolated--usually each phase. Both ends of the winding-under test should be connected to the test equipment and both ends of the other winding should be grounded. Preferably the tests should be performed when the winding temperature is as near ambient temperature as possible; tests should not be made if the winding temperature exceeds 40° C. Insulation resistance, absorption, and surface moisture vary with temperature, so for comparable results temperatures should be as nearly the same as possible. For safety, the winding must be grounded immediately after the test is concluded.

43. Very low frequency (VLF) tests. The voltage distribution for 60-Hz dielectric tests is determined by the capacitance and resistance of the insulation; this distribution stresses that the winding be the same as in normal operation, but the test equipment is cumbersome. The voltage stresses during DC high-potential tests depend on leakage current, which gives a different voltage distribution along the coil length from that during normal operation. These tests have the advantage of small, portable test equipment and less damage in case of a failure and have the capability of monitoring changes in insulation as the test progresses. In order to gain some of the advantages and eliminate some of the disadvantages of both AC and DC dielectric tests, very low-frequency overvoltage tests have been suggested. Tests using a frequency of 0.1 Hz appear to stress the insulation similarly to the stress distribution in service (Bhimani 1961a) and to reduce the capacitive current 600 times (nonresonant test equipment), allowing less expensive, portable test equipment. VLF tests are proof tests similar to 60-Hz tests and do not allow monitoring the condition of the insulation during the test.

44. VLF test procedures are the same as the normal frequency tests described under the section on AC high-potential tests. The presently accepted equivalent peak voltage for the VLF tests is 1.63 times the RMS value of the AC normal frequency test voltage. These values are twice normal line-to-line voltage plus 1,000 V, 85 percent of this value after the windings have been installed in the field, and 125 to 150 percent of normal line-to-line voltage after the machine has been in service, all times 1.63 to give the VLF

crest voltage. Whether to use the equivalent of 125 or 150 percent for maintenance tests depends somewhat on the age and condition of the insulation. VLF test equipment has also been used to measure insulation power factor and partial discharges in conjunction with partial discharge test equipment. These 0.1 Hz tests are based on difference between phases, between similar units, or past tests for interpretation. ASEA, Ltd. has developed and sells a 55 kV, 6.5 kVA, 0.1 Hz test set, and the James G. Biddle Co. markets 0.1 Hz test sets rated up to 150 kV peak.

45. Partial discharge tests. Partial discharges, as opposed to breakdown of the insulation, are discharges that do not bridge the insulation between conductors. Corona is a partial discharge that occurs when the potential gradient is sufficiently high to ionize the air, such as occurs in voids in the insulation or on the surface of end turns. Mica insulation is highly resistant to corona discharges, and with proper attention to winding design and installation, corona has generally not been a significant problem.

46. Slot discharges, another form of partial discharge, can be very damaging to the insulation. Generator manufacturers developed improved high-voltage with the use of mica impregnated with thermosetting resins with greatly improved properties. This insulation is hard and inflexible in comparison to the older thermoplastic insulations and has been beset with slot-discharge problems. Slot discharges occur when part of a coil side in a slot is not in contact with the stator core and the semiconducting coating does not ground the insulation surface. Under this condition, a surface charge on the higher potential coils will develop on the insulation and cause a discharge to the stator core that, depending on the surface area to be discharged, can be of sufficiently high energy to rapidly cause severe damage to the ground-wall insulation. Because of improved dielectric strength of the insulation, the ground-wall insulation is thinner, and potential gradients through the insulation are higher, so that application of semiconducting material on the insulation surfaces in the slot portion of the winding becomes important to improve the stress distribution. Insulated bars in slots are subject to forces from leakage, main fluxes, and conductor temperatures. Stator coils have to be installed sufficiently tight so that they are adequately supported throughout their length to prevent undue vibration. The stator slots are about half-filled with the insulation material plus wedges,

filler, and packing, which are subject to compressive forces and deformation. The wedges, filler, and packing are also made from insulating materials. The original prestress can be lost over a period of time, leading to looseness of the coils, coil vibration, abrasion of the insulation, destruction of the semiconducting properties of the outer tapes, loss of grounding of the insulation surfaces, and slot discharges. The following methods presently used to detect slot discharges and corona:

a. Corona probe test. The Corona Probe Test is made with a 2 in long by 0.25-diam ferrite probe wound with 11 turns of No. 18 AWG copper magnet wire, connected by coaxial cable to a broad band amplifier and peak voltmeter. The circuit and meter are tuned to 5 MHz. The probe is mounted on the end of an insulated stick. With the rotor removed, the stator windings are energized at the normal 60-Hz operating voltage (8,000 V for 13.8 kV generators) and the probe is placed across the slot enclosing the coil. Figure 6 shows an electrical diagram for a typical corona probe. There has been some success in measuring slot discharges with the rotor in place, with the probe at the top of the slots (Fort and Henriksen 1974), or with a modified probe developed by the Tennessee Valley Authority (TVA), which consists of a ferrite loop stick that is smaller and more easily used without removing the rotor. Both internal corona and slot discharges can be detected by the voltmeter. Varying discharge intensities can be distinguished by this method; however, harmful and acceptable levels have not been established. Measurements are made at several locations on each coil, giving an overall picture of the ionization pattern for the entire winding. This pattern is primarily for the top conductors in the slots with considerably reduced sensitivity for the bottom conductors. Corona can be detected in the end turns by a small antenna (about 1 in. long) installed in an insulated housing and mounted on an insulated stick. The antenna output is amplified by an audio frequency amplifier, with earphones, a voltmeter or a cathode ray tube (CRT) for indication. Extreme caution should be used in making these tests as the winding is energized.

b. Blackout test. The generator must be disassembled with the rotor removed for this test and the top of the generator barrel covered with black plastic sheets to exclude light. The winding is energized to normal operating voltage; observers standing in the space for the rotor away from the winding should look for partial discharges and note their location.

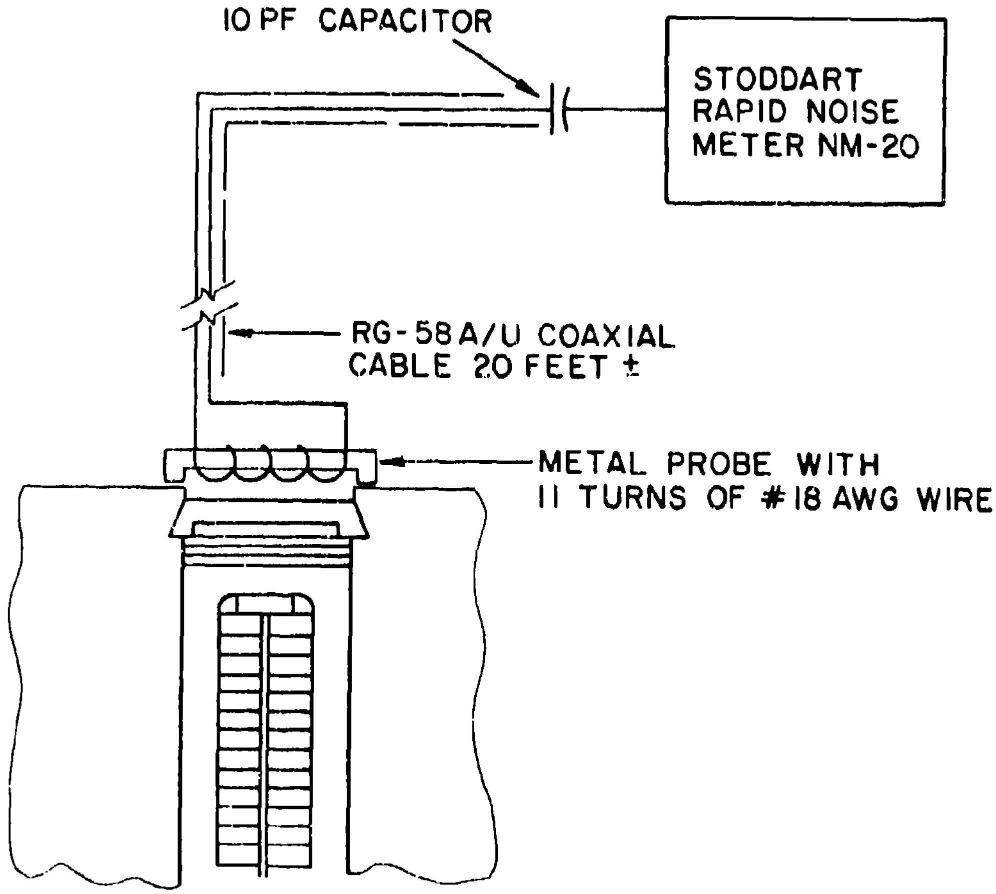


Figure 6. Typical slot discharge detector (Corona Probe)

c. Generated frequency EMI monitoring. Generated frequency EMI monitoring can be a useful maintenance tool to detect semi-conducting surface deterioration and loose coils and to detect partial discharges within the insulation structure. Comparison of measurements over a period of time that show an increase in EMI under approximately the same ambient noise conditions may indicate developing slot discharges or corona, especially at frequencies below about 2 MHz. One test is made using coupling capacitors connected to the machine terminals, neutral, or in the machine winding. A high pass filter and pulse discharge analyzer are also necessary. The coupling capacitors can be temporarily or permanently installed. The analyzer was

developed by the Canadian Electric Association and is described by Kurtz and Lyles (1983). Tests described by Kurtz and Lyles showed less than 60 mV for windings in installed new condition, 60 to 150 mV for windings with some looseness of the coils, and over 150 mV for very loose coils with loose wedging and packing. These readings were obtained for peak pulses on the oscilloscope. A refinement of this test uses equipment that measures the number of pulses per second with magnitudes falling between an upper and lower threshold. Another test used extensively in the United States utilizes a precision high-frequency current transformer installed in the generator neutral that supplies a wide-band radio-frequency spectrum analyzer developed by Westinghouse (Timperley 1983). Frequency domain analysis allows identification in some cases of the noise source. Measurements using both of these test methods are made with the machine in service and usually include a great deal of noise from external sources. It is difficult to identify measurements unless the partial discharges are of sufficient energy. To help identify the source of the noise, two wide-band coupling capacitors can be connected to a wide-band differential amplifier as shown in Figure 7. System noise arrives simultaneously, resulting in zero output, whereas a partial discharge pulse occurring internal to the generator arrives at the differential amplifier inputs at a different time, resulting in an output. Figure 8 is a plot of microvolts (quasipeak) as a function of frequency of the measured quantity for a machine with serious slot-discharge problems. Measurements were made using the spectrum analyzer developed by Westinghouse. Tests can be made at rated speed and voltage connected to the system at no-load, or at rated load and voltage. Although operating while connected to the system during testing increases noise from external sources, the effect of load current on the conductors can be included to give an indication of whether the EMI is caused by mechanical looseness of the conductors. These tests can identify the location of partial discharge in phases or circuits, depending on the number and location of transducers.

d. Powerfactor and powerfactor tip-up. Insulation powerfactor is the cosine of the angle between the applied test voltage and current through the insulation. For most stator insulations in good condition, the powerfactor will be in the neighborhood of 1 percent. A perfect homogeneous insulator will have a powerfactor versus voltage curve that is a straight line, since the powerfactor will not change with voltage. When partial discharges occur, the powerfactor will increase with applied voltage. The difference between the powerfactor at 25 and 100 percent of normal line-to-ground voltage is defined as the powerfactor tip-up. A bar graph of the powerfactor tip-up for a large number of generators is shown in Figure 9. This test is used as an acceptance test for new coils and as a maintenance test. When the test is used to detect weaknesses in the

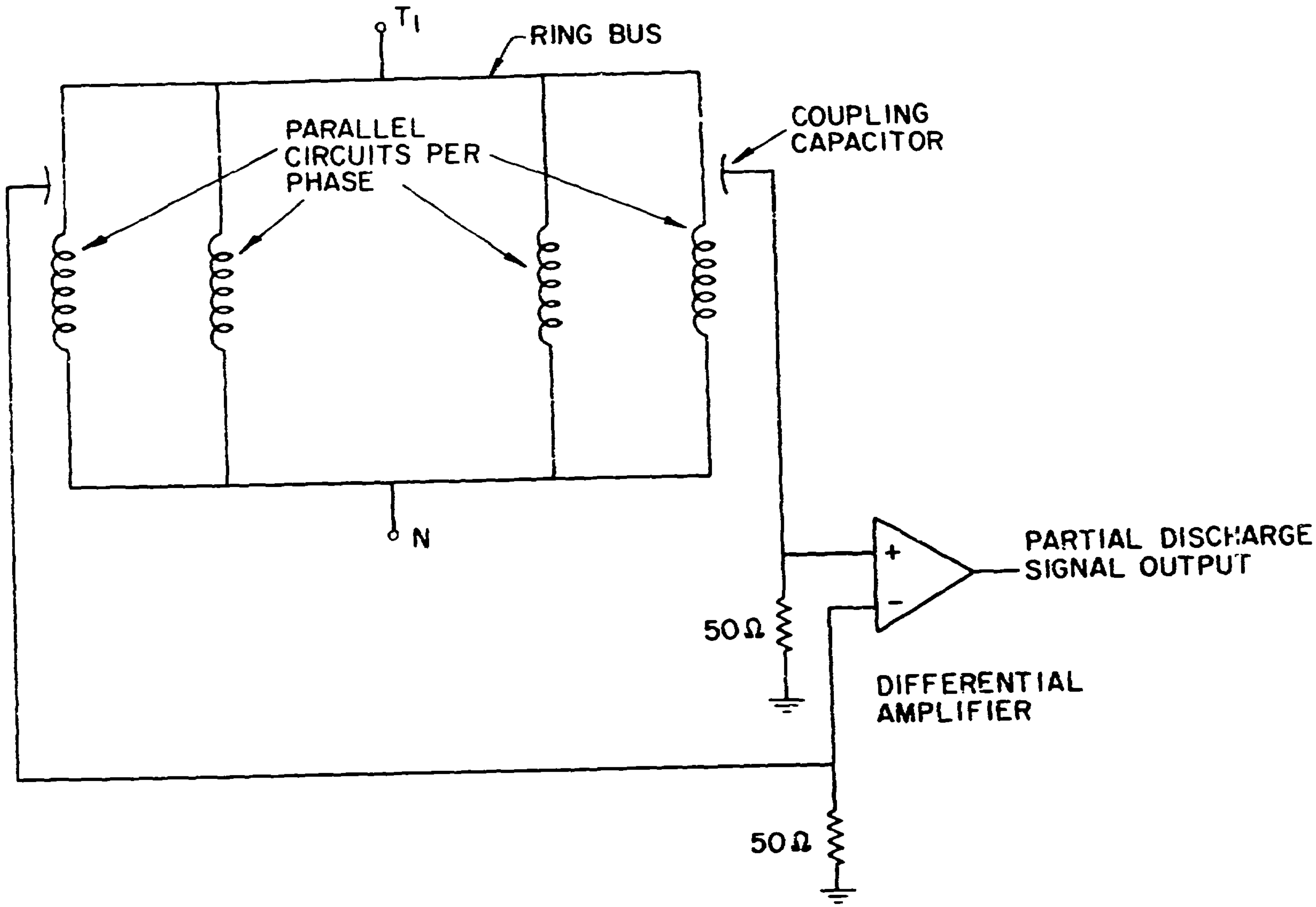


Figure 7. EMI measurements using differential coupling

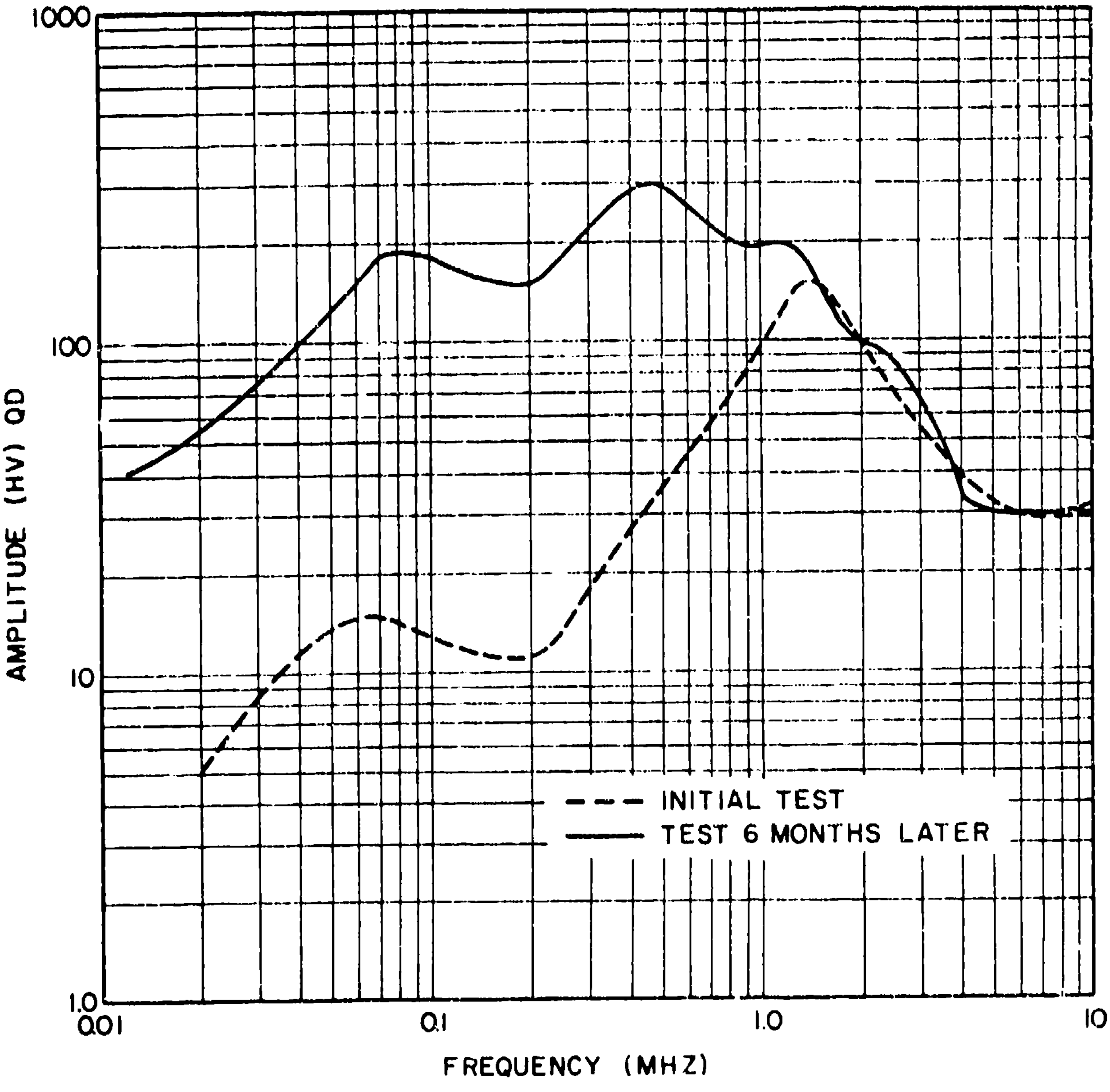


Figure 8. Spectrum changes due to soot discharges

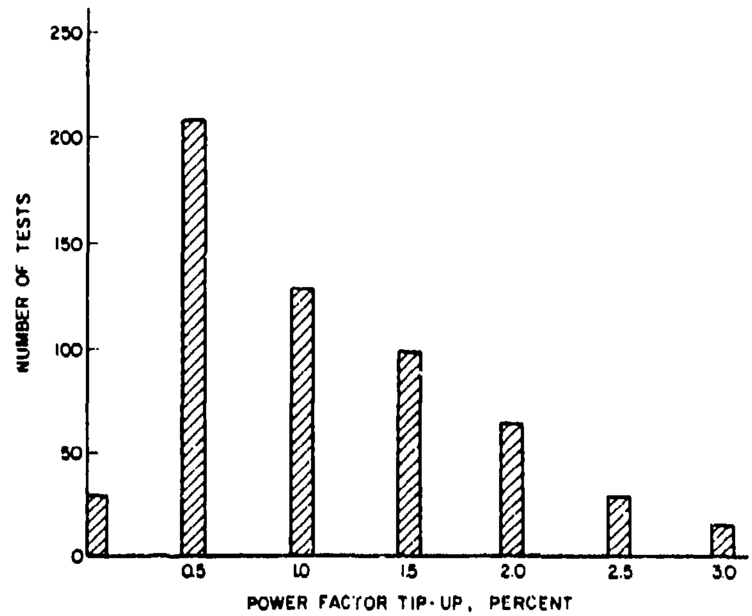


Figure 9. Powerfactor tip-up for approximately 600 units

insulation, the test must be made on only a single coil, or at the most two or three coils. Powerfactor and powerfactor tip-up tests can be made on an entire winding to measure average values of powerfactor to detect increasing partial discharge activity over a period of time. When powerfactor measurements show an increase in powerfactor or powerfactor tip-up over a period of time, some insulation deterioration is likely. Figure 10 shows how insulation condition can affect insulation powerfactor as a function of test voltage. Powerfactor and powerfactor tip-up tests should be made at room temperature with the coil or coils disconnected and adjacent coils not under testing ground. Powerfactor varies with temperature so that tests on the same unit should be made when the temperature is as near the same as possible. The test voltage is increased from zero to 120 percent of normal rated line-to-ground voltage with several readings of charging currents, dielectric loss and powerfactor taken, including readings at 25 and 100 percent of voltage. Accuracy of the measurements should be within 0.2 or 10 percent of the measured value. Powerfactor tip-up is usually less than 2 percent. Test equipment should be grounded and test leads shielded. The test voltage should be 60 Hz applied between the conductor and stator core. A typical test circuit is shown in Figure 11. To reduce the size and capacity of the test equipment, a resonant circuit is employed using a null-balance method for comparison against an internal standard to measure insulation powerfactor and dielectric loss. Powerfactor tip-up and corona probe tests can be closely correlated when the tests are made under the same conditions (Fort and Henriksen 1974).

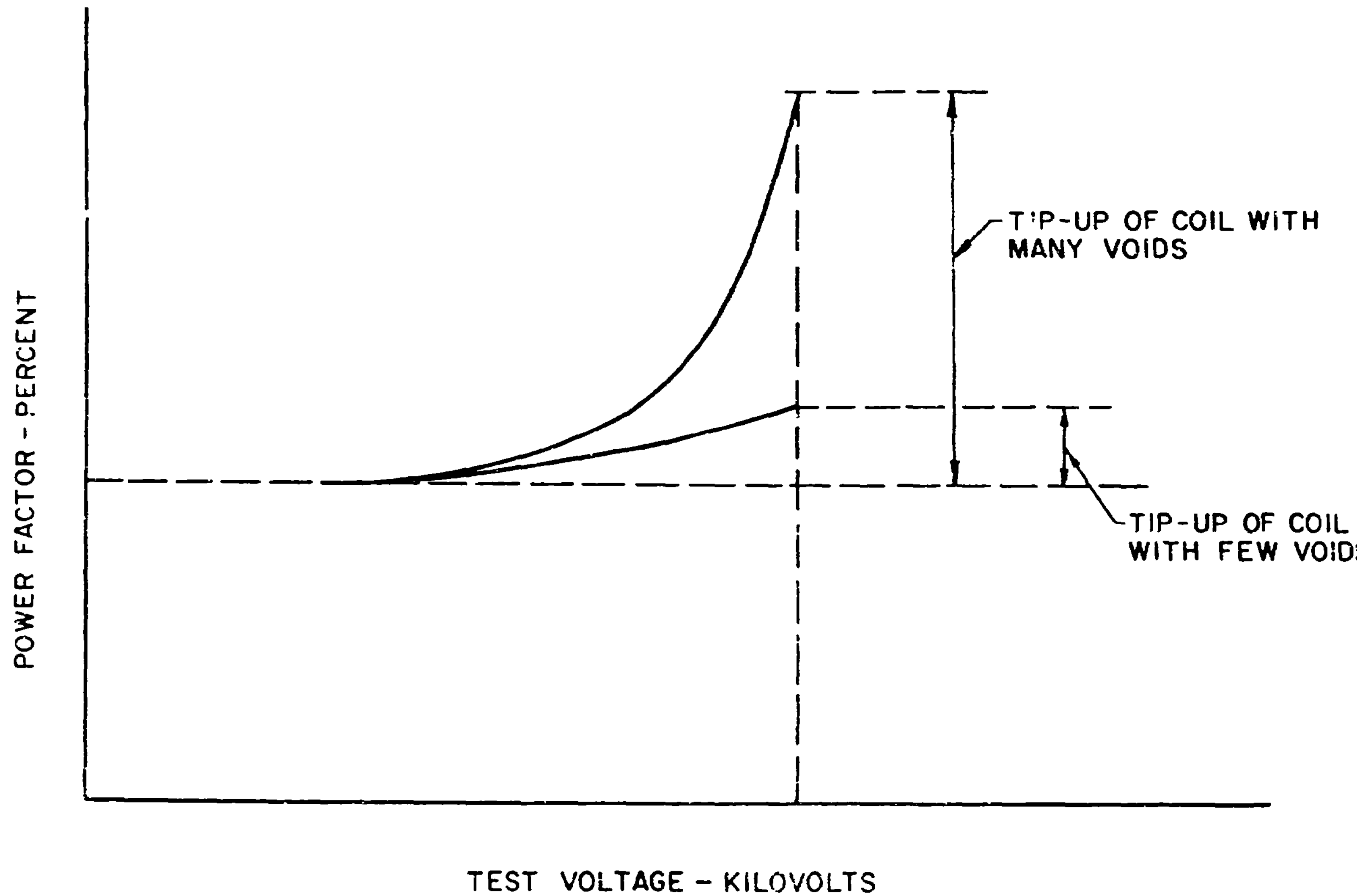
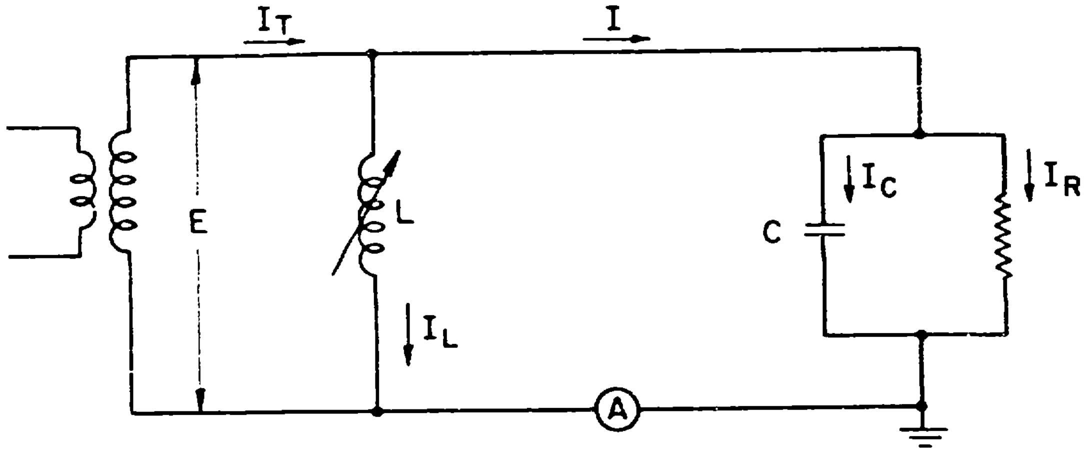
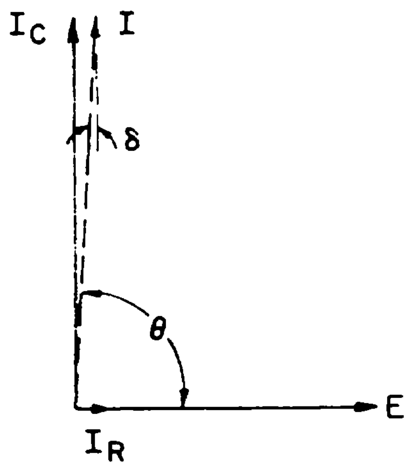


Figure 10. Powerfactor tip-up for different insulation conditioners



FOR RESONANCE: $jX_L = -jX_L, \; 2\pi + L = \frac{1}{2\pi fC}, \; L = \frac{1}{(2\pi f)2C}$



$$I_T = -j\frac{E}{X_L} + j\frac{E}{X_C} + \frac{E}{R} = \frac{E}{R}$$

$$PF = \frac{EI\cos\theta}{EI} = \frac{EI_R}{EI} = \frac{I_R}{I}$$

$$W = \frac{E^2}{R}, \; R = \frac{E^2}{W}$$

$$I_C = \frac{E}{X_C} = E2\pi fC, \; I \cong I_C, \; C = \frac{I}{\omega E}$$

DIELECTRIC DISSIPATION FACTOR = $\cot\theta$ = $\tan\delta$

DIELECTRIC POWERFACTOR = $\cos\theta$ = $\sin\delta$

Figure 11. Resonant circuit for powerfactor and dielectric loss measurement

e. Coil to core resistance. Stator coil insulation surfaces are always provided with a semiconducting material to ground the coil insulation to the stator iron. This material must have a resistivity high enough to avoid shorting the stator core laminations but low enough to prevent charges from building up on the surface of the insulation that could cause electrical discharges. Coil-to-ground insulation should be determined when the winding is new and should be checked periodically. An increase in resistance indicates some erosion of semiconducting material and thus the potential for development of slot discharges. For this test, the rotor must be removed and the resistance measured with an ohmmeter and a suitable probe between the coil sides at the air ducts and the stator iron. Measurements should be made at three or four places along the coil sides. It is usually necessary to measure only the resistance of the top coil sides to ground as they generally are indicative for the whole winding and are more accessible. Measurements are most important on coils located away from the neutral end of the winding. Acceptable values of resistance should be obtained from the manufacturer.

f. Ozone detection. Ozone concentration tests are a useful method of detecting the presence, and to some extent, the intensity of partial discharges. Simple sampling and chemical testing equipment are available that will give a sensitive and reasonably accurate measurement of ozone concentrations inside the generator housing. Ozone in low concentrations (0.3 percent or less) is fairly stable in the absence of oxydizing substances so that measurements can be compared after a specified number of operating hours, starting from a base value. When ozone concentrations increase, the possibility of dangerous slot discharges should be investigated with the use of the tests previously described. The increase in ozone concentration is proportional to the total energy in the discharges and is an indication of their intensity. Humidity, temperature, and operating time since the last test should be considered when evaluating results.

47. Turn-to-turn insulation tests. All of the tests previously described test the ground-wall insulation. Turn insulation integrity on multiturn coils is important because a turn-to-turn failure will usually develop into a ground fault and result in a service outage. Turn insulation is stressed by steep-front voltage waves caused by lightning and switching surges. Turn faults can also be caused by loose strand vibration. Capacitors and special arresters are installed at the generator terminals for surge protection to slope and limit the amplitude of impulse voltages. Surge protection is important to limit voltage stresses between turns. With the usual high-resistance generator neutral grounding, surge arresters must be

rated for line-to-line voltage with some loss in protection. Split-phase generator differential relaying is normally used with multicircuit generators with multiturn coils for turn-to-turn fault protection, but this method of detecting turn faults depends on detecting small differences between large currents and cannot be relied on to detect single turn faults (Sills and McKeener 1953).

48. Test equipment is available that can be used for proof testing turn insulation where the insulation is questionable as when there is suspicion that a failure-to-ground began as a turn fault. Multiturn coils have such a low impedance that it is impossible to impress sufficient voltage on the turn insulation at normal frequency.

49. Effective methods have been developed, however, which reliably detect shorted turns and proof-test turn insulation. One method is to induce a voltage in the coil being tested by placing two laminated iron test cores over the slots containing the test coil. A two-turn surge-inducing coil and a single-turn search coil are placed in slots in the laminated cores and are used to energize the stator coil under test and to observe the induced voltage on an oscilloscope. A surge generator is used to apply a steep-front repetitive voltage to the surge coil, which oscillates at the natural frequency of the circuit. Figures 12 and 13 show the arrangement of the mechanical and electrical equipment for testing turn-to-turn insulation. The surge generator is basically a capacitor that is repetitively charged and discharged. Frequencies in the range of 3,000 to 10,000 Hz provide a uniform voltage distribution throughout the coil, but are not too high to cause saturation of the iron. The pulse interval is usually about 3 sec. The peak test voltage recommended is 75 percent of the rated RMS line-to-line voltage but not less than 350 V per turn for maintenance proof tests. For new coils the recommended peak voltage is 100 percent. The manufacturer should be consulted before making this test as turn-to-turn tests are potentially destructive, and the selection of voltage levels that will search out bad coils but not harm good coils has not been established. The test can sometimes be made without removing the rotor by only removing a few poles.

50. An accepted test procedure is to observe the wave form on the oscilloscope for a coil before and after the coil has been deliberately short-circuited. A line coil has been deliberately short-circuited. A line coil is

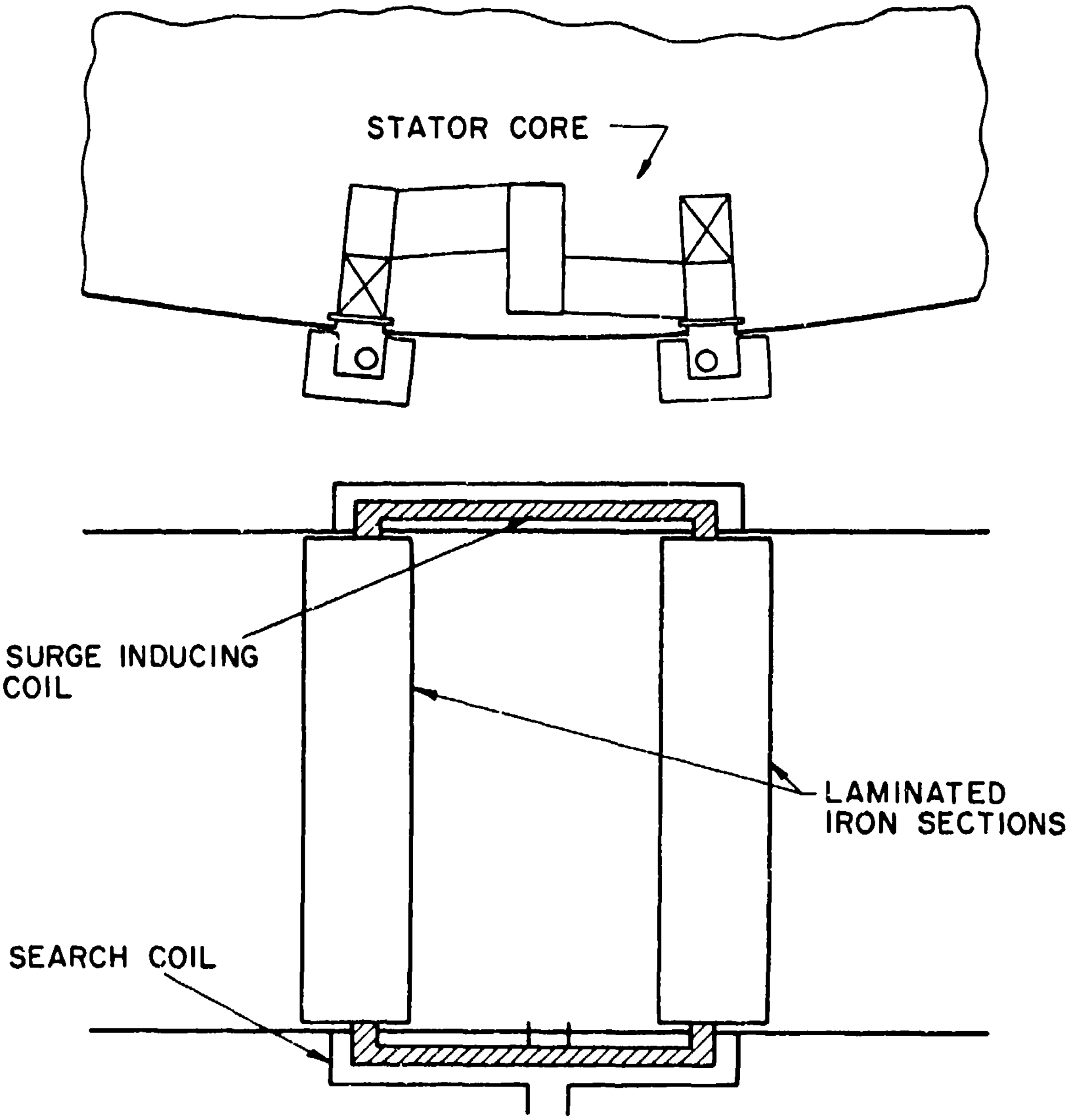


Figure 12. Surge testing arrangement for turn-to-turn insulation

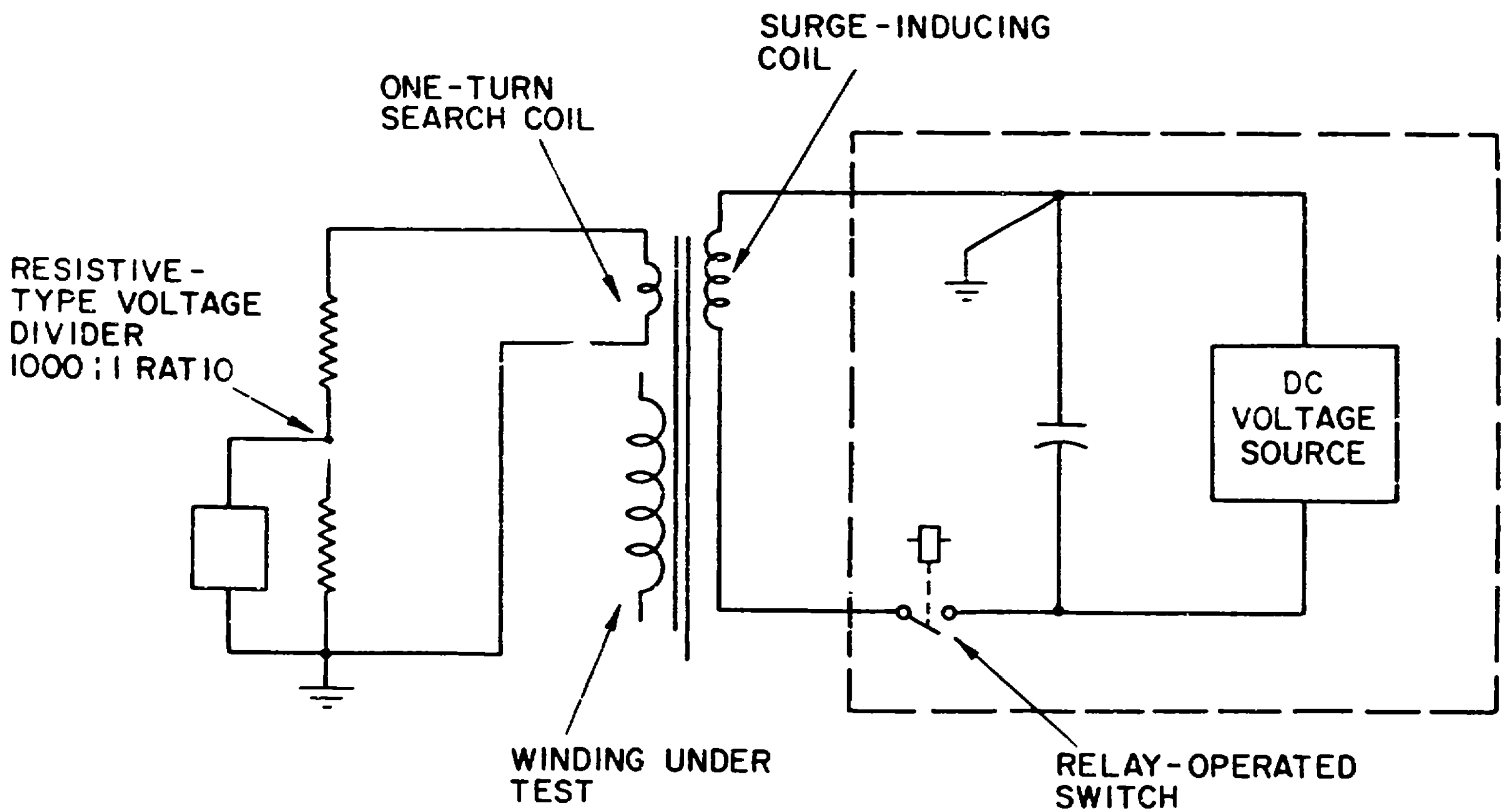


Figure 13. Equipment electrical connections for turn-to-turn tests

usually used so that insulation at only one coil connection need be removed. The wave forms thus obtained are used for calibrating the tests on the rest of the coils.

51. Turns in multiturn coils are proof tested by the manufacturers before installation in accordance with individual test procedures and test values that they have established over the years. Corps of Engineers specifications require turns to be tested with a potential of at least 10 times normal operating voltage between adjacent turns.

52. Shorted turns can be detected by a stator winding resistance test. A kelvin bridge is usually used to measure the resistance of the smallest number of coils that can be easily isolated. The test should be made at room temperature, the winding temperature accurately determined, and the resistance corrected to standard temperature conditions for comparison with previous measurements. A decrease in resistance may indicate shorted conductors, and an increase in resistance, an open circuit or poor connection.

Temperature detector insulation test

53. A number of 10-ohm copper resistance temperature detectors (RTDs) are embedded in the generator stator winding and used as sensors for scanning, indicating, and recording stator temperatures. Three leads are brought from each RDT to a terminal cabinet in the generator housing. One lead from each RTD is connected to a common ground. Since an RTD insulation failure-to-ground can allow damaging circulating current to flow, RTD insulation should be periodically checked by disconnecting the terminal cabinet ground connection and externally connected measuring equipment and by testing the insulation of all RTD's to ground. A 500 DC potential is usually used for this test.

Stator thru-bolt insulation test

54. The stator core is made up of thin steel laminations coated with an insulating material to minimize eddy-current losses. The laminations are firmly held in place by clamping fingers or flanges at both ends, held tightly with stator thru bolts. The insulation resistance of the stator thru bolts to ground should be measured periodically with a low DC voltage. A suitable value of test voltage can usually be obtained from the manufacturer. Torquing of the thru bolts should be periodically checked to verify proper clamping pressure.

Stator core interlamination insulation test

55. When it is believed the core laminations may be damaged and some of the lamination insulation ineffective or when a unit is rewound, the stator core can be tested by magnetizing it to its approximate normal peak magnetization and measuring the core temperature around the inside of the stator bore. An insulated 5 kV unshielded cable is wound around the stator core and adequately secured. The cable should be of sufficient size and number of turns to obtain the desired magnetization and evenly distributed around the core to obtain a uniform flux distribution. The number of turns and conductor size can be determined in accordance with IEEE Standard 56 (IEEE 1977a). A single turn of No. 18 AWG or larger insulated conductor also should be placed around the core and connected to a voltmeter to check that the core is magnetized to the desired number of volts per turn.

56. The temperature of the core should be monitored for hot spots with an infrared detector, thermometers, pyrometers, parafin shavings, or other suitable means. Excitation should be applied for sufficient time to allow overheated areas to become evident. This process can take 20 min or longer. A record of stator temperature should be made with the stator temperature recorder, if possible.

Rotor winding insulation tests

57. Rotor winding insulation sytems are described in section 5.2. Insulation for field windings is not subject to most of the stresses that adversely affect stator winding insulation. Most field winding insulation sytems have provided many years of trouble-free service. There are a few tests, however, that should be made periodically in the maintenance test program.

58. Insulation resistance tests. Field winding insulation resistance tests to ground are made in accordance with the applicable procedures described under the insulation resistance tests for the stator winding, paragraph 2.7.1.1. The voltage used for the resistance measurements is usually 500 DC.

59. Dielectric tests. When the generator is completely assembled in the field, dielectric acceptance tests are made by the manufacturer. The field winding is tested at 10 times rated excitation voltage but not less than 1,500 V. Nominal excitation-system voltage ratings are between 125 and 500 V. Test

potential is 60 Hz, which is applied for one minute. Rotor-winding dielectric tests are seldom used as routine maintenance tests, but when field-winding insulation is suspect, a proof test can be made up to 75 percent of the acceptance-test potential. In preparation for this test, the brushes should be raised or insulated from the slip rings to avoid applying the test potential to the excitation system. The tests should be made when the temperature is as near room temperature as possible, but they can be made up to rated-load operating temperature. The test potential is applied between the field-winding conductors and the rotor frame with the stator windings and rotor frame grounded.

60. Shorted turn detection. Shorted turns are usually a result of mechanical distress resulting from overspeed or mechanical shock or excessive temperature. Although machines have operated for long periods of time with shorted turns in the field winding, shorted turns increase excitation current and field temperature and can cause vibration. The easiest method of detecting shorted turns at standstill is to apply 100 V 60 Hz AC to the rotor winding and measure the voltage drop across each pole. A field coil with shorted turns will have a longer voltage drop than a sound coil. Adjacent coils may also have reduced voltage drop. Shorted laminations can also result in a lower than normal voltage drop. A running impedance test can be performed by applying 100 V, 60 Hz, across the winding and noting any changes in impedance as speed increases. Sometimes this test is necessary to detect intermittent shorts.

61. Rotor winding resistance and temperature can be accurately measured and the resistance compared to the original value measured during the acceptance test and corrected to the same temperature. A lower value of resistance is an indication of shorted turns; a higher value, poor connections. Any change in resistance of more than about 2 percent should be investigated.

Laboratory insulation tests

62. When coil failure has occurred or when the condition of the insulation on a coil has deteriorated to the point where replacement is advisable, sections of the coil can be sent to the manufacturer, a testing laboratory, or tests can be conducted in-house by trained personnel for analysis and recommendations as to the condition of the insulation, causes of

deterioration, and applicability to other coils still in service. The tests on multiple coils give an average of the insulation properties for the entire test section. The smaller the test section, the more sensitive the test can be, and tests can be carried to destruction. Electrical tests previously described can be made on small specimens. The coil insulation can be dissected so that visual, microscopic, and x-ray observations can be made, and electrical and mechanical tests can be performed in accordance with American Society for Testing and Materials (ASTM) standards. A few of these standards are briefly described at the end of this section.

63. Factors causing deterioration of the insulation are temperature, voltage, thermo and electro mechanical forces, and the environment. Environmental factors, except contamination from oil, dust and moisture, are usually not a significant factor.

64. Thermal aging. The thermal life of insulation systems depends on the material, operating temperature, and time of exposure. Degradation can be measured by changes in electrical and mechanical properties. Thermal aging can be evaluated by measuring the dimensions of the specimen, the dissipation factor and capacitance as a function of voltage, and the electrical strength of the insulation.

65. Voltage endurance. Insulation breakdown from long-time high-voltage stress is caused by erosion by electrical discharges and electrochemical attack causing breakdown of chemical bonds in the insulation surface. High potential tests, powerfactor tests, and dissection and visual inspection can be used for analysis.

66. Thermomechanical forces. Operating temperature and thermal cycling affect the mechanical strength of insulation. Tape separation, girth cracks, and insulation migration are functions of differential thermal expansion and contraction. As the copper conductors expand with temperature, insulation in the slots is restrained from moving by friction, but insulation on the end turns is free to move. This movement causes tensile stress and can cause cracking because of the differential movement. Electrical tests, such as high-potential proof tests and powerfactor tests, and microscopic examination can be used to detect thermomechanical degradation.

67. Electromechanical forces. Electromechanical forces such as those caused by sudden short circuits and out-of-phase synchronizing can cause

distortion and cracks in end-turn insulation. Vibration of loose coils in slots caused by magnetic forces can cause abrasion of the insulation. These phenomena are evident from the appearance of the coils, but the extent and importance of the damage and the effect on reliability for continued operation can be determined by tests, including powerfactor, high potential dielectric tests, and microscopic examination.

68. ASTM tests. Some applicable tests included in ASTM Standards are listed below:

a. ASTM-D-3151. This test is not specifically applicable to generator insulation but will provide information on electrical breakdown at elevated temperatures.

b. ASTM-D-3382. This test provides a measurement of capacitance and loss characteristics by obtaining the integrated charge transfer and energy loss caused by partial discharges from measured increases in capacitance and tan delta with voltage.

c. ASTM-D-3426. Impulse strength of solid insulation is measured with a standard 1.2-by 50-μ sec voltage wave.

d. ASTM-D-3755. The breakdown voltage of solid insulation under DC stress is measured for comparison with new insulation.

e. ASTM-D-149. The breakdown voltage of solid insulation is measured at 60 Hz.

f. ASTM-D-257. This standard covers procedures for determination of insulation resistance, volume resistance, volume resistivity, and surface resistance and surface resistivity. These values give an indication of the effect of exposure to abnormal temperature over a period of time on electrical insulating materials.

g. ASTM-D-150. This standard covers procedures for measuring relative permittivity, dissipation factor, loss index, powerfactor, phase angle and loss angle, all of which are an indication of deterioration of electrical insulating materials.

h. ASTM-D-2304. Expected remaining thermal life data are obtained from oven tests followed by tests for flexural strengths in accordance with ASTM-D-790, water absorption in accordance with ASTM-D-570, and electrical strength in accordance with ASTM-D-149.

PART III: PERIODIC ROUTINE INSPECTION AND TESTING

Current Practice

69. A survey was made by the Construction Operations Division in OCE in 1983. A questionnaire was sent to all divisions with hydropower responsibility on current programs for periodic maintenance tests for hydroelectric generators. The results of this survey, updated to the present, are presented in this section.

a. Stator and rotor insulation resistance tests are made by all divisions routinely, but the time between the tests varies from 1 to 4 years. These test are also made whenever a unit has been out of service for maintenance or to test repaired or new windings.

b. The rotor pole drop test is routinely made by all of the divisions except one. The time interval between tests also varies from 1 to 4 years between divisions.

c. Stator and rotor winding resistance tests are made periodically by about half of the divisions, and the time between these tests, where they are made, also varies between 1 to 4 years.

d. Polarization tests are routinely made by three divisions every 2 to 4 years. All divisions make this test on new or repaired windings or after an extended outage.

e. Powerfactor or dissipation factor tests are made routinely by only two divisions, one annually and one every 4 years.

f. DC overvoltage tests are not being made routinely by any division at the present time. One division did make this test routinely on units with insulation that was in poor condition, but these units have been or are in the process of being rewound, and the routine DC overvoltage tests have been discontinued. Although not using the test at the present time, one division plans to initiate this test in the near future on all units; the test will be done every 4 years, with the BuRec tester, which automatically provides a constant rate of ramp voltage adjustment with an automatic plotter. Several other divisions have used this test infrequently, sometimes to help locate faults. Except as indicated above, none of the other divisions plan to make this test routinely.

g. Corona probe tests have only been made routinely (every 4 years) by one division, but most of the divisions make this test when there is an indication of trouble. The corona probe tests are

usually made with the rotor in place unless it has been removed for other reasons. The division making this test routinely tests only the units with thermosetting insulation.

h. Ozone concentration tests are made periodically by four divisions with testing intervals from monthly to more or less yearly. One division makes ozone concentration and blackout tests periodically, on units with thermosetting insulation only.

i. Generated frequency electromagnetic interference is not at present being monitored routinely by any division, but four divisions plan to initiate some form of routine EMI monitoring. All of the test engineers contacted believe that some type of routine partial discharge testing should be done on units with thermosetting insulation. One division is planning to initiate an inservice testing program soon so that units with thermosetting insulation will be tested every 6 months. The equipment to be used is under study. Another division has installed both cable and lumped capacitor couplers in units at four plants and has obtained four of the analyzers developed by the Canadian Electric Association described in Kurtz and Lyles (1979). At this division, the test engineers are enthusiastic about this test for units with thermosetting insulation, but there are no plans to do the test routinely.

j. Visual inspections are made by all of the divisions with the frequency and extent of the inspections depending somewhat on the frequency and type of routine electrical tests being made. Also the frequency and extent of the visual inspections depend on outages for other reasons, condition of the insulation, results of previous inspections and tests, and available manpower.

70. A summary of the reports on routine electrical maintenance tests by the divisions is included in Appendix A.

Proposed Routine Inspection and Testing Program

71. A routine insulation-testing program should be established and implemented for hydroelectric projects at which continuity and reliability of service are important. The purpose of the program is to discover trends and minor insulation problems before they become major and to reduce unscheduled outages to a minimum. The routine inspections and tests should be made periodically at regular intervals. The testing program will usually be coordinated with the annual maintenance and major overhauls and will depend on when unit outages can be scheduled. Time intervals between tests will vary

because of circumstances at each project and in each division; for example, whether the tests are made by project personnel or a central testing staff would affect the intervals. In general, however, inspections and some tests should be made annually, except as noted; however, where operating conditions are not severe and the history of these and similar units does not indicate a need for tests this often, time between some of the routine tests can be extended. All units should be tested wherever possible, but depending on the number of units, available manpower, and availability of the units for scheduled outages, it may not be practical to test each unit annually. In these cases, units to be tested should be selected according to the number of starts and stops, type of load, and stator temperatures and variations.

72. The loss of revenue for a 30-day outage at John Day for one unit is estimated to be about $750,000, depending on load and flow conditions. The potential loss of revenue from the sale of power for an unscheduled outage, the value of the equipment, and the cost of major repairs make it easy to justify the routine inspections and tests. They can usually be made by two men in two or three 8-hr days, depending on the test conducted. If the tests are made during the annual overhaul, test time is not usually required to obtain unit clearances and minor disassembly.

73. In addition to the routine tests made periodically, these tests and special tests described previously should be made when indicated by the results of previous inspections and tests, by electrical, visual/or audible indications of trouble, or for demonstrating suitability for service after an extended outage or winding repairs. All electrical tests should be accompanied by a visual inspection.

74. The following tests should be included in a routine insulation maintenance testing program as described:

a. Visual inspection - all units, annually.

b. Stator insulation resistance, dielectric absorption, and polarization - all units, annually.

c. Rotor insulation resistance, dielectric absorption, and polarization - all units annually.

d. Rotor pole drop - all units, annually.

e. Stator winding resistance - all units, annually.

f. Rotor winding resistance - all units, annually.

g. Powerfactor and powerfactor tip-up - all units, every 5 years.

h. Ozone concentration - units with thermosetting insulation, every 6 months.

i. Generated frequency EMI monitoring - units with thermosetting insulation, every 6 months.

j. DC controlled overvoltage - older units with poor insulation, as needed.

Visual inspection

75. A careful inspection, without major disassembly, should be made of the generator stator and field windings, stator core, and field poles annually. Mirrors, borescopes, probes, and special light sources can be a help in viewing inaccessible locations. The visual inspections should be made annually, even though in some cases a large number of covers have to be removed in addition to the housing coverplates. Many defects can only be found by a visual inspection.

Insulation resistance, dielectric absorption and polarization tests

76. These tests indicate the average condition of the winding insulation with regard to insulation contamination by moisture or other contaminants that could lead to failure. These tests cannot distinguish flaws or localized defects in the insulation. They do, however, give a good indication of the cleanliness and dryness of the insulation. Test equipment frequently used is the James Biddle Megger, 500/2,500 V.

Rotor pole drop test

77. This test is made to detect shorted turns in the field winding. A low 60-Hz voltage is applied to the winding and the voltage drop measured across each pole. Shorted turns are indicated by a lower than normal voltage. A variac, ammeter, and accurate low scale voltmeter are usually used for this test.

Winding resistance tests

78. A bridge should be used to measure the DC resistance of the stator and field windings for comparison with the values by the manufacturer during the generator acceptance tests. The values, when corrected to the standard temperature of 75° C, will indicate shorted, loose, or open conductors or

vaporization of volatile constituents of the impregnating compound. The increase in powerfactor with voltage is an indication of the total number and size of voids in the insulation. The degree of internal coil deterioration is proportional to the powerfactor tip-up. This test needs to be made only every 5 years unless there is evidence of increasing partial discharge activity. Equipment frequently used for this test is the Doble MH Test Set.

Ozone concentration tests

80. Partial discharges in air generate ozone proportional to the total discharge energy. A simple chemical indicator can be inserted into a hole in the generator housing to measure the ozone concentration. This measurement is not accurate, but comparative values are a good indication of increasing partial discharge activity when the ozone concentration is increasing. If ozone concentration is greater than 0.1 ppm, monthly tests should be made. If less, tests should be made every 6 months. Careful records, including a plot of ozone concentration as a function of time, should be kept for machines with levels over 0.1 ppm. When levels exceed 0.6 to 0.8 ppm for large machines, corrective action should be considered.

Generated frequency EMI monitoring

81. Many units with thermosetting stator insulation show evidence of partial discharges, mainly slot discharges. These discharges often increase quite rapidly in number and intensity to cause, in a short period (sometimes in 6 months or less), significant deterioration of the groundwall insulation unless the conditions responsible are corrected. At the present time, EMI monitoring tests have not been standardized, and acceptable equipment and values have not been determined. The most useful data is that obtained from periodic tests on the same machine, under the same conditions, with the same test equipment. Under these conditions, calibration is not important. The partial discharge analyzer developed by the Canadian Electric Association described by Kurtz and Lyles (1979) is recommended for this test, with coupling capacitors permanently installed in the units. EMI can be monitored at the generator neutral, line terminals, or at the ring busses for each circuit or each phase, with the results used for comparison and to help locate the EMI source. Tests should be made with the unit under load to include the effects of magnetic forces on the conductors. Early detection of slot discharges is important and will usually provide conclusive evidence of loose

wedges and coils. This test need not be made on units with asphaltic insulation, but should be made every 6 months on units with hard, epoxy-impregnated insulation.

<u>DC-controlled overvoltage tests</u>

82. Before a unit is first put into service, a DC-overvoltage test should be made to demonstrate that the machine meets specification requirements. For 13.8 kV generators, this test is made at 41.33 kV (twice normal plus 1.0 kV times 0.85 times 1.7). When this test is made, the DC voltage should be increased steadily or in one-minute steps up to 29 kV and the current plotted as a function of voltage for benchmark data to be compared with subsequent tests. Barring unexpected problems, it is not necessary or advisable to include this test in a routine testing program until insulation deterioration makes reliable operation questionable. As units become older and integrity of the insulation becomes suspect, DC-controlled overvoltage tests can be added to the routine test program to demonstrate that the machine can be expected to provide reliable service. An equivalent maximum test voltage of 125 percent of rated line-to-line voltage (29 kV for 13.8 kV generators) is high enough for this demonstration. The routine tests previously described in this section can detect weaknesses or flaws in sound insulation. Such localized flaws can only be found with high potential tests, but these tests have the disadvantage that the voltage applied and test time are arbitrary, and finding a defect will require repair caused by the failure. The equipment sometimes used for this test is the USBR Ramp-Voltage Test Set and the Biddle 60 kV Hipot Test Set.

PART IV: CRITERIA FOR REWINDING GENERATORS

Rewinding

83. Over half of the generators at Corps of Engineers hydroelectric plants have been operating for more than 20 years. As the units approach the end of their useful service lives, increasing numbers will experience stator winding insulation distress and failures. Considerations in determining when to rewind a generator should include the economic, availability, and reliability factors described below.

84. The economic considerations in generator rewinds involve costs and benefits that are hard to define quantitatively. Consider the economic benefit of postponing investment for an arbitrary period for purchase and installation of a new winding, the likelihood of a major failure and the estimated cost of repair, the economic loss for an extended unscheduled outage, and the chances of this happening.

85. Benefits more easily evaluated are the reduction in cost for rewinding if the unit must be disassembled for other reasons, and the economic benefits that can be realized by increasing the capacity of the generator.

86. Scheduled maintenance and repairs are planned in accordance with the marketing agency or system dispatcher and with load demand and available water and head. In some cases, however, forced or unscheduled outages can result in loss in revenue from the sale of power. It is possible that when a failure causes major damage and an extended outage, the cost of repair and loss of revenue can approach the cost of rewinding.

87. The economic loss caused by an unscheduled outage will depend a great deal on the conditions at the time at each particular project. Some of these are the environmental and hydraulic conditions at the time of the outage, reservoir storage available, the demand for power, the values of capacity and energy, and the amount of potential energy that would be wasted. Losses can vary from zero to more than $25,000 a day. Every unscheduled outage reflects on plant reliability. The importance of reliability is difficult to quantify, but unscheduled outages always have an adverse effect on the system that can vary from fleeting minor deviations from tie line schedules, voltage schedules, or system frequency to major system

breakups and power outages. Extended outages also have adverse effects on the system depending on the unit capacity compared to the system capacity, the reserve capacity available during peak load periods, availability, requirements, and cost of replacement power, and adverse effects on plant dependable capacity.

88. At most plants the likelihood of major damage and an extended outage resulting from an insulation failure is fairly remote. Single phase-to-ground faults will not cause any significant damage when the generators are grounded through a distribution transformer and secondary resistor. This is the normal grounding method; it limits ground fault current to only 10 or 15 A. Major damage will occur with resistor or reactor grounding, phase-to-phase faults or multiple-ground fault; the latter two occurring with any type of grounding. A single phase-to-ground fault impresses line-to-line voltages on the other phases-to-ground with distribution transformer-resistor grounding, slightly increasing the possibility of multiple-ground faults for windings with bad insulation. Most phase-to-ground faults are unlikely to cause major damage resulting in an extended outage. Units can be operated satisfactorily with a few failed coils cut out of the winding and bypassed. Also if the insulation deterioration can be attributed to voltage-related causes, rewinding can sometimes be delayed by reversing the line and neutral ends of the winding. When a unit must be disassembled to remove the runner (as for turbine repairs), rewinding the generator should be considered if the experience with similar units operated under similar conditions and signs of aging and deterioration of the insulation indicates the likelihood of winding failures before the next major overhaul, even though visual inspections and tests do not indicate imminent failure. The decision to rewind the generator at this time must be based on sound engineering judgment as to the expected remaining life of the winding.

89. There are no hard and fast rules that can be established for generator rewinding when certain definable conditions exist. Such decisions will always be subjective and will require sound engineering judgment. It is Corps practice to operate generators until failure. The following criteria, in addition to the considerations discussed previously, should be used as

guidance. Units should usually be rewound when competent engineering judgment indicates that the following conditions are significant:

a. Multiple failures occur over a fairly short period of time (1 to 2 years or so), and the conditions causing the failures are evident throughout the machine and cannot be corrected.

b. The winding failures are similar in nature and can be attributed to general insulation deterioration.

c. Mechanical, visual inspections and electrical tests described in this report show that there is generalized insulation deterioration.

90. To prepare, advertise and award a contract to rewind a generator requires a minimum of 60 days. Depending on the size and type of unit (Francis or Kaplan) and the extent of other work to be done, such as modifications to the excitation system or the thrust bearing lubrication system, completing the work can take from 3 to more than 6 months. Consequently, when the unit is experiencing insulation failures and the mechanical and visual inspections and electrical tests described in this report show generalized deterioration and reduced integrity of the insulation, the unit should be promptly scheduled for rewinding with consideration of budget restraints.

Uprating

91. During the energy shortage in the seventies, generator rewinding could be justified by uprating the units at some plants that had potential for significant additional capacity. At the present time, rewinding generators with sound insulation solely for increased capacity would be difficult to justify economically at most plants. However, when units are scheduled for rewinding, studies should be made to determine the practicality and economic feasibility of increasing the turbine and generator nameplate capacity. The nameplate capacities of most of the older units and plants were based on a high plant factor with major benefits based on the dependable average annual energy. (Plant factor is the ratio of the average load over a specified time to the plant rating.) As time passed, base load was supplied mainly by thermal plants and peak loads by hydro plants. It became economical to size hydro plants to supply peak demand for only a few hours a day. The value of

capacity varies between systems and depends somewhat on the characteristics of the load and the mix of thermal and hydro generation, but in all systems supplied by power from Corps of Engineers hydro plants, the value of capacity has increased markedly. The changing relative values of capacity and energy mean plants can be rated higher with lower plant factors under the same hydraulic conditions and with increased revenues from the sale of power. For most older plants, there is a real economic incentive to uprate the generators, and uprating should be considered whenever units are rewound.

92. Hydraulic conditions and turbine performance curves must be reviewed to establish a reasonable increase in capacity. Tailwater fluctuations, amount of storage, and flow and head duration are important considerations as are turbine capacity and efficiency as a function of head, and discharge and turbine cavitation limits. Mechanical stresses and electrical considerations limit increases in capacity of 120 percent of the 115 percent nameplate rating, unless detailed turbine and generator designs are available from the manufacturers. Corps of Engineers specifications have always limited stresses under maximum normal operating conditions to one-fifth of the ultimate strength or one-third of the yield (or equivalent) of the material. An increase in capacity of 120 percent results in increases from 0.2 to 0.24 times the ultimate strength and 0.33 to 0.4 times the yield strength. Any reduction in safety margins exceeding the above is unacceptable.

93. Conductors insulated with thinner, thermosetting, epoxy-impregnated insulation replacing the older, thicker asphaltic insulation allow space for an increase in copper cross section, easily permitting 20 percent higher stator current with losses and temperature rises equal to or less than the existing winding. As long as the increased output does not require modifications to the field winding or other major equipment, the cost for rewinding is about the same for any increase in capacity up to about 20 percent, as the slot dimensions are fixed and insulation thickness and copper cross section costs are similar. Field current necessary for operation at rated powerfactor will increase when the output is increased. Often field windings have sufficient excess capacity to allow a 20 percent uprating without any modifications; however, field temperature rises must always be investigated. Capability curves as shown in Figure 14 should be developed and compared with actual field currents and temperatures. The capability curves

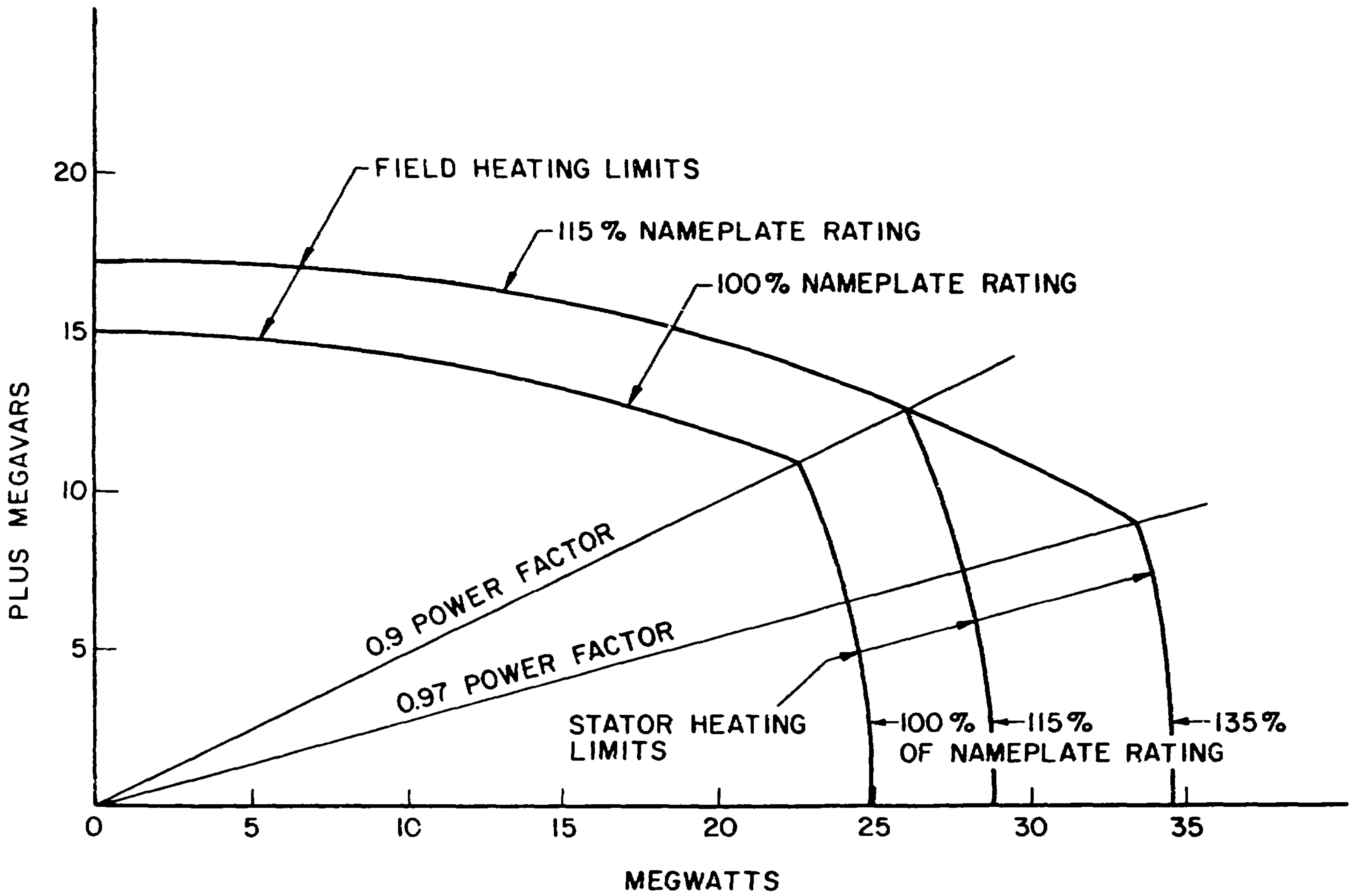


Figure 14. Generator capability curves

in Figure 14 were for units with a rated powerfactor of 0.9. These units always operated at a powerfactor between 0.95 and 1.0, and as shown on the curves, increasing the powerfactor rating to 0.97 allows a 20 percent increase in capacity without any increase in field current.

94. There have been major improvements in excitation and voltage regulating systems in the last 25 years. It is usually good practice to modify or replace these systems on older generators even though they have adequate capacity. The capacity of generator output leads, generator circuit breakers, governors, power transformers, and high voltage equipment such as circuit breakers, disconnecting switches, current transformers, and bus and line carrier equipment must be investigated. These factors may limit uprating in some cases. Uprating generators increases fault currents, and circuit-breaker interrupting capacities should be investigated. Instrument scales, meters, relays, and current transformers may require modifications or replacements in some cases.

PART V: CORPS OF ENGINEERS EXPERIENCE WITH THERMOSETTING INSULATION

95. The first Corps of Engineers units with thermosetting insulation were at the Chief Joseph Project in the Seattle District. The first unit at Chief Joseph went into operation in 1956. The generators were furnished by Westinghouse and were supplied with their new (at that time) thermalastic polyester-impregnated stator coil insulation. Up to that time, generator stator insulation consisted of asphaltic impregnated thermoplastic insulation. Subsequent to Chief Joseph, some other units furnished by Westinghouse with thermosetting polyester insulation were at Buford (1957), Table Rock (1959), Hartwell (1962), Big Bend, Dardanelle, and Beaver (1965), and Millers Ferry (1970). At Chief Joseph, the units were operated at overloads exceeding 135 percent and were used regularly for system regulation. Considering the severe duty, the insulation performed very well. Except for several winding faults at Big Bend, the insulation at the other plants has been as good or better than the older asphaltic type insulations. None of the problems associated with units with epoxy-impregnated insulation occurred on units with polyester insulations. The first Corps of Engineers units with epoxy-impregnated stator coil insulation were furnished by General Electric (GE) for the John Day project on the Columbia River. The first John Day unit went into operation in 1969. After only a year of operation, it was discovered that most of the units had loose wedges and loose coils in the slots. Further investigation disclosed that many of the stator coils had lost most of the semiconducting material on the slot portions of the coil surface and the ground insulation was being damaged by high-energy slot discharges from the insulation surfaces to the stator core and by abrasion from coil vibration. Because a great deal of ozone was generated by the partial discharges, some of the generator housings had to be vented outside. Thermal and magnetic forces resulting from normal operation caused the insulation to permanently deform so that loss of prestress and loosening of the coils occurred in the slots.

96. Small areas of the coil surfaces became ungrounded, giving rise to nonuniform potential gradients with sufficient potential to generate slot discharges between coil surfaces and ground. Thinner insulation with higher potential gradients was a contributing factor. Slot discharges increased from

isolated, small energy discharges to high energy discharges that covered most of the slot portion of affected coils. Because the discharges caused a chemical reaction between the semiconducting material (carbon) and oxygen, the semiconducting material disappeared. The slot discharges increased in number and intensity as the semiconducting material was lost.

97. A corrective program was initiated to tighten the coils in the slots by replacing side filler and rewedging and to re-establish coil-side grounding by forcing semiconducting room temperature vulcanizing silicone (CRTV), a caulk-like elastic material, between the coils and stator iron at the air ducts. Initially this treatment was effective, but before long slot discharges and ozone concentrations began to increase. It was reasoned that ungrounded islands on the coil surfaces remained after the treatment and were getting progressively worse. The neutral and line ends of the windings were finally reversed in the belief that the lower-voltage coils were still effectively grounded. The rehabilitation program at John Day was not entirely successful, however, and did not prove to be a permanent solution.

98. The units at Lower Monumental (GE 1969), Little Goose (GE 1970), Lower Granite (Westinghouse 1975) and Jones Bluff (Westinghouse 1975) exhibited some or all of the same problems as at John Day. It became necessary to rewedge and retighten the coils at these plants after only a short period of operation. All 16 units at John Day, 3 units at Lower Monumental, and 3 units at Lower Granite have been, or are in the process of being, rewound. The units at Jones Bluff were reconditioned in a manner similar to those at John Day, but so far they have not re-experienced any of the original problems. The problems described at John Day occurred to approximately the same degree on most of the generators world-wide during the first years of experience with thermosetting epoxy-impregnated insulation. Experience has shown that close tolerance must be maintained in the manufacture of coils, wedges, slot fillers and packing, and the coils and supporting systems must be designed and installed to hold the coils tightly in the slots. Frequent inspections and tests are essential to confirm that coils remain tight and there are no slot discharges.

PART VI: CONCLUSIONS

99. Current insulation inspection and testing varies widely between divisions depending on their own experience and testing philosophy. Electrical tests are well known and test equipment readily available that, when used along with thorough visual inspections in a regular routine insulation-maintenance program, can extend insulation life and reduce unscheduled outages, reducing the possibility of loss of revenue from the sale of power and major equipment damage. A routine inspection and testing program can find minor problems that can be corrected before they become major. A regular inspection and testing program can indicate the present condition of the insulation and can reveal the need for special tests and long-term trends. Increasing numbers of units are going to need to be rewound because of advancing age and problems with thermosetting insulation systems. There is a need for guidance to help the field offices determine when to rewind generators.

PART VII: RECOMMENDATIONS

100. The following annual routine inspection and testing program is recommended for all generators:

- a. Visual inspection.
- b. Stator and rotor insulation resistance.
- c. Rotor pole drop.
- d. Stator and rotor winding resistance.

101. The following tests are recommended every 6 months for units with thermosetting epoxy-impregnated insulation systems:

- a. Ozone concentration.
- b. Generated frequency EMI monitoring.

102. In addition to the above, a Power Factor Tip-up Test should be made every 5 years, and a DC-controlled overvoltage test should be made when needed on units with bad insulation.

103. The following criteria are recommended for consideration in determining when to rewind a unit:

- a. Possible economic benefit by postponing rewinding.
- b. Likelihood and cost of a major failure.
- c. The possibilities and estimated economic loss of revenue for an extended unscheduled outage.
- d. Saving by rewinding during a major overhaul.
- e. Economic benefit of uprating.

104. In addition to the above tests, some of which are difficult to quantify, units should be rewound when multiple failures occur over a short period of time and the failures are attributed to general insulation deterioration that cannot be economically corrected.

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APPENDIX A: SUMMARY OF FIELD TESTS

1. The following information was obtained during the latter part of October and the early part of November 1986.

Mr. Clay Fouts - North Pacific Division (NPD)

2. DC-controlled overvoltage tests have been used infrequently in NPD. Tests have been made on only a few units, and there are no plans to make these tests routine. The tests have been made with the USBR ramp-type equipment.

3. Pulse discharge measurements have been made at Dworshak, Lost Creek, John Day, and Libby. NPD has four analyzers developed by the Canadian Electric Association described in detail in Kurtz and Lyles (1979). NPD test engineers are enthusiastic about this test, but there are no plans to perform this test routinely. Both cable and 4 x 4 in. cylindrical capacitors have been used for coupling. Corona probe measurements have also been made on some units.

4. Units with thermosetting insulation are in the process of being rewound or have been rewound at John Day (all 16 units to be rewound by 1990), 3 units at Lower Monumental, and 3 units at Lower Granite.

Mr. Ed Westmeyer - Southwestern Division (SWD)

5. Ozone tests are made routinely in the Little Rock District but only when trouble is suspected at the other district in SWD. Also SWD has made corona probe tests only when problems are suspected. This nonroutine test is made at the top and bottom of the coils without removing the rotor. AC- and DC-overvoltage tests are made only on new windings by the manufacturer. Units at Dardanelle, Beaver, and Table Rock were furnished with Westinghouse thermalastic insulation. No other units in SWD have thermosetting insulation except units which have been rewound. All rewound units do, and SWD is considering some form of routine partial discharge monitoring on the units at Bull Shoals, Broken Bow, and Tenkiller Ferry.

Mr. Dave Eldredge - Nashville District, Missouri River Division (MRD)

6. Plans are to make routine partial discharge tests of some kind on units that are rewound. Nashville District now makes corona probe tests on the top and bottom of the coils without removing the rotor when there is indication of trouble. DC high-potential tests have been made to help locate

coil failures. There have been 5 to 6 coil failures at Old Hickory, and these coils have been cut out of the winding and bypassed, resulting in sizeable circulation currents. The units at Old Hickory have been scheduled for rewinding.

Mr. Oliver Ness - Omaha District, MRD

7. Omaha District has rewound 3 units at Fort Peck, 5 units at Garrison, 7 units at Oahe, and 3 units at Givens Point, all with epoxy-impregnated insulation. Those units were rewound because of failing coils. The Big Bend units were installed in 1965 with Westinghouse polyester-impregnated thermosetting insulation. All the other units in Omaha District had thermoplastic insulation until rewound. The Big Bend units have had 3 or 4 failures that started as turn-to-turn faults, probably caused by partial discharge activity in the turn insulation. When the units at Garrison were rewound during the recent energy shortage, the generator stator cores were replaced with a considerable improvement in efficiency.

8. No partial discharge test is presently being made, but this test is being considered for the units that have been rewound. DC-controlled overvoltage test were made routinely in the past on units with failing insulation but have been discontinued as the units have been rewound.

Mr. George Counts - South Atlantic Division (SAD)

9. SAD plans to initiate a DC-controlled overvoltage test from 30-32 kV on all units every 4 years. The test equipment to be used will be the Bu Rec ramp-type tester for automatic constant ramp voltage adjustment plotter. SAD also plans to initiate partial discharge test using TVA couplers and a peak reading rf voltmeter. The plan is to take readings every 6 months on all units with thermosetting insulation. Corona probe tests have been made every 4 years on units with thermosetting insulation without removing the rotor.

10. Experience with polyester insulation at Buford (1957), Hartwell (1963), and Millers Ferry (1970) has been good. The only problem with these units was the coils becoming loose on one Miller's Ferry unit and slipping down; Jones Bluff was supplied with epoxy-impregnated insulation which had all the typical problems of loose coils, loss of insulation grounding, and slot discharges. The coils were repaired in a method similar to the ones used at John Day without further serious problems to date. Richard B. Russell and St.

Stevens, the only other units with epoxy-impregnated insulation, have not evidenced any problems.

11. In SAD, routine tests take two men approximately 2 to 8 days to complete. Before the tests, units are taken out of service for clean-up and visual inspection so that time for equipment clearances, etc. are not charged to the tests.

Summary of routine tests

12. A summary of the routine tests on generator insulation made by the Corps is shown in the following table. The information was taken from responses to a questionnaire sent by OCE-CWOM to the divisions with hydropower responsibilities in 1983. The information was updated to the current practice as of November 1986.

Table A1

Routine Tests and Interval Between Tests*

Tests	SAD Thermo-setting Insula.	SAD Thermo-plastic Insula.	Omaha	Kansas City	Vicksburg	NPD	SWD	Nash-ville
Visual Insp.	4	2	1	1	1	1	1	3
Stator Ins. Res.	4	2	1	1	1	1	1	3
Rotor Ins. Res.	4	2	1	1	1	1	1	3
Pole Drop	4	2	2	1	1	4		3
Stator Wind Res.	4	2	1		1			3
Rotor Wind Res.	4	2	1					3
Polarization	4	2					1	3
Powerfactor	4	4			1			
Blackout	4					4-6		
Corona Probe	4							
Ozone	1/12-1/6		1/3-1			1/12	**	
EMI Monitor	***		***				***	***
DC Overvolt	+	+	++			+		

*Unless otherwise indicated, all districts in one division follow the same test program.
**Made routinely in Little Rock District.
***Plans to initiate routine EMI monitoring.
+Plans to initiate routine USBR ramp test every 4 years.
++Tested every 5 years to 34 kV until units were rewound.